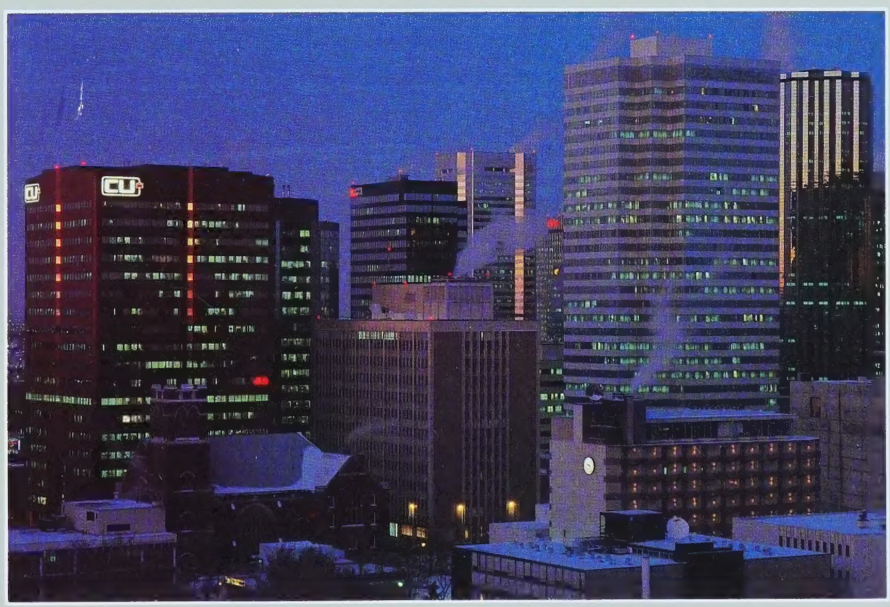
CANADIAN UTILITIES LIMITED

1984 ANNUAL REPORT

CORPORATE MISSION



Canadian Utilities Limited is an investor-owned company committed to expand in the business of generating, transmitting, distributing and selling electric power, and in the business of producing, transmitting, distributing and selling natural gas, while providing safe, dependable service at just and reasonable rates; and to aggressively pursue non-utility growth by seeking out and participating in energy and resource-related opportunities, while earning returns sufficient to attract and maintain the confidence of investors.

CONTENTS

CORPORATE STRUCTURE

CANADIAN UTILITIES LIMITED

- ALBERTA POWER LIMITED (Canada) 100%
- NORTHWESTERN UTILITIES LIMITED (Canada) 96.5%[1]
- CANADIAN WESTERN NATURAL GAS COMPANY LIMITED (Alberta) 95.9%[1]
- ATCOR RESOURCES LIMITED (Alberta) 100%
- THE YUKON ELECTRICAL COMPANY LIMITED (Yukon Territory) 100%
- NORTHLAND UTILITIES (B.C.) LIMITED (British Columbia) 100%
- NORTHLAND UTILITIES (N W T) LIMITED (Northwest Territories) 100%

This chart shows the names of CU's operating subsidiaries, the jurisdictions in which they were organized and the percentages of their voting securities owned by CU.

Note 1: The minority interest is by way of voting non-participating preferred shares.

FRONT COVER:

A bronze sculpture entitled "The Lineman" by John Weaver was commissioned by Canadian Utilities in 1984 and now forms part of the Company's collection of Canadian art.

PAGE ONE:

The Company logo on the upper faces of the Canadian Utilities Centre is now a highly visible feature of the downtown Edmonton skyline.

OPPOSITE:

Construction proceeds on a new electrical substation near Beaverlodge, Alberta to serve oil and gas development in the Elmworth Field.

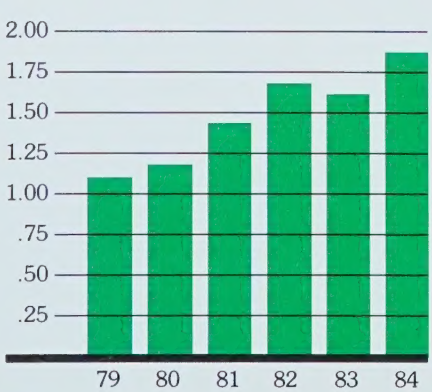
HIGHLIGHTS

	1984	1983	Increase (Decrease)
Revenues (thousands)			
Natural gas	**$ 861,218**	$ 928,427	$ (67,209)
Electric	**340,345**	327,241	13,104
Non-utility			
Energy operations	**162,203**	123,573	38,630
Other	**664**	569	95
Total	**$1,364,430**	$1,379,810	$ (15,380)
Earnings attributable to shares* (thousands)	**$ 101,405**	$ 87,116	$ 14,289
Earnings per share*	**$ 1.87**	$ 1.62	$ .25
Equity per share* (at year-end fully diluted)	**$ 11.36**	$ 10.57	$ .79
Dividend per share*			
Annual	**$ 1.08**	$ .86	$ .22
Fourth Quarter	**$ .30**	$ .26	$ .04
Shares* outstanding			
Average for the year	**54,211,574**	53,806,928	404,646
Year-end	**54,211,574**	54,211,574	
Capital expenditures (thousands)	**$ 242,478**	$ 290,185	$ (47,707)
Customers at year-end			
Natural gas	**593,558**	580,667	12,891
Electric	**143,401**	139,890	3,511

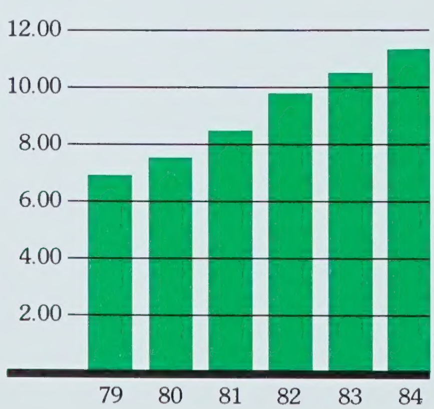
* Class A non-voting and Class B common shares

CANADIAN UTILITIES LIMITED

Earnings per Class A and Class B Share
(in dollars)



Equity per Class A and Class B Share
(in dollars)



TO THE SHAREHOLDERS

Canadian Utilities Limited earnings attributable to Class A and Class B shares for the year ended December 31, 1984 were $101.4 million ($1.87 per share) compared to $87.1 million ($1.62 per share) for the previous year.

The growth in earnings is related to a number of items including an expansion of the utility rate base, increased electric sales, cost control programs and the significantly increased contribution to earnings from ATCOR Resources Limited, CU's non-utility subsidiary.

Revenues in 1984 declined to $1.364 billion from $1.380 billion, largely because of the removal on February 1, 1984 of the Natural Gas and Gas Liquids Tax which had been collected in the natural gas rates and flowed through to the Federal Government.

The Company's natural gas and electric customer base continued to expand during the year with the number of natural gas customers increasing 2.2% to 593,558 and the number of electric customers growing 2.5% to 143,401.

Natural gas throughput for 1984 was up 4% over 1983. While natural gas sales continued the decline of the past several years, greater volumes of gas transported through the Company's pipelines on behalf of large industrial users and exporting companies resulted in a net increase in throughput. Electric sales to retail customers in 1984 increased 7.3% compared to the previous year. ATCOR's growth occurred largely in the natural gas marketing and oil and gas exploration and development segments of its business.

Total assets at December 31, 1984 were $2.469 billion compared to $2.367 billion a year earlier.

Chairman of the Board and Chief Executive Officer R. D. Southern (seated) and J. D. Wood, President and Chief Operating Officer.

Northwestern Utilities Limited, CU's natural gas utility serving north-central Alberta and the Lloydminster area, received approval from the Alberta Public Utilities Board for an interim refundable rate increase, effective November 1, 1984. The interim increase permitted Northwestern to collect an additional $10.0 million in revenues for 1984 and an additional $25.0 million for 1985. A final decision on Northwestern's allowed 1984 and 1985 revenues is expected in 1985. Both Northwestern and its sister company in southern Alberta, Canadian Western Natural Gas Company Limited, were given Public Utilities Board approval to reduce rates following the removal of the Federal Natural Gas and Gas Liquids Tax on February 1, 1984. Canadian Western was able to avoid a rate increase application in 1984.

At year-end, Alberta Power Limited, CU's electric utility subsidiary, appeared before the Public Utilities Board to establish the terms of reference for a rate proceeding during which Alberta Power's revenues and costs for 1984 and 1985 are to be considered. Alberta Power's current rates were approved by the Utilities Board in 1983.

In July 1984, the Alberta Electric Utilities Planning Council issued its latest forecast showing slower growth in Provincial electric energy requirements compared to its 1983 forecast. Subsequently, Alberta Power and TransAlta Utilities Corporation, APL's partner in the Sheerness generating plant, submitted to the Energy Resources Conservation Board a request for a further delay in the completion of Sheerness Unit 2, scheduled for commissioning in 1987. Under the current forecast, power from Unit 2 will not be required until 1990. No further delay is proposed for Unit 1 which is essentially complete and scheduled for commissioning in January 1986. At the time of writing the ERCB had just completed hearings to consider the rescheduling of Sheerness Unit 2 and Edmonton Power's Genesee plant, also under construction. A decision is expected early in 1985.

CU's non-utility subsidiary, ATCOR Resources Limited, continued to achieve excellent earnings growth during 1984. ATCOR Resources is a shareholder in AT&S Exploration Ltd., which has an interest in the Amauligak discovery well in the Beaufort Sea. Test results from the well indicate commercial quantities of oil and natural gas. Delineation wells are being drilled to determine the production potential of the area.

Early in 1985, ATCOR announced that it was developing plans for the

OPPOSITE:
A new 406-mm pipeline to increase the capacity of the Imperial Oil fertilizer plant near Fort Saskatchewan was installed in the fall.

construction of two natural gas liquid recovery plants in the Carbon and Joffre areas and a natural gas liquids pipeline between Carbon and Joffre. Additional details of the Company's utility and non-utility operations are contained elsewhere in this report.

In March 1984, CU redeemed its 10¼% Cumulative Redeemable Second Preferred Shares Series A for $25.70 a share including 45¢ of accrued dividends. Funds for the redemption came from a private placement of Cumulative Redeemable Second Preferred Shares Series J priced at $25.00 to yield 8.375%. During the second quarter, the Company issued $100.0 million of 13.10% unsecured debentures maturing June 1, 1994 with a five-year retraction privilege. Proceeds were applied to the Company's capital expenditure program.

In October, the Board of Directors declared a fourth-quarter dividend of 30¢ per Class A non-voting and Class B common share, up from 26¢ in the previous four quarters. This was the 14th increase in the common share dividend in the past 13 years.

The Alberta economy is still undergoing an adjustment process from the activity levels reached during the boom period, particularly in the housing and commercial construction sectors. However, in the medium to long-term, the Province's economic outlook is improving. Overall real economic growth rates are forecast by the Company to recover to the 3-3½% range and remain at that level in the 1986-1990 period.

With the prospect of relatively stable world oil prices and without significant reduction in government take and without increased gas exports, the total upstream investment by the oil and gas industry is expected to remain static in real terms. Recent moves towards market-responsive pricing of natural gas exports to the United States should result in significant volume increases. These increased volumes, even at reduced prices, should increase net revenues to Alberta producers, which should increase oil and gas investment in Alberta and thus stimulate economic growth in Alberta and Canada generally.

Effective June 1, 1984 on the retirement of E. W. King as President and Chief Executive Officer after 28 years of distinguished service, R. D. Southern became Chairman and Chief Executive Officer, J. D. Wood, President and Chief Operating Officer, and W. R. Horton, Executive Vice-President, Utilities. W. A. Elser was appointed President and Chief Executive Officer of ATCOR Resources Limited.

At CU's annual general meeting on April 26, 1984, shareholders approved an increase to 18 from 16 in the maximum number of members of the Board of Directors. Newly elected to the Board were W. R. Horton and C. M. Leitch, Q.C.

The Board of Directors wishes to record its sincere gratitude for outstanding service to Keith Provost, who will retire on March 31, 1985 as Senior Vice-President, Alberta Power Limited, and D. R. Brandt, who retired on November 2, 1984 as Vice-President, Canadian Utilities Limited.

Succeeding Mr. Provost as Senior Vice-President and General Manager, Alberta Power Limited, will be C. O. Twa, currently Vice President Customer Services for Alberta Power. P. K. F. McEwen, Manager of Alberta Power's East Division, has been appointed to succeed Mr. Twa as Vice-President Customer Services.

The Board also wishes to thank W. D. Grace, who resigned from Canadian Utilities as Senior Vice-President, Finance and a Director, on March 1, 1985, for his contribution to the success of the Company.

Employees deserve special commendation in 1984 for their effective response to the Company's cost reduction and productivity improvement programs. Thanks in large measure to their hard work and readiness to adapt to changing economic circumstances, the Company was able to record improved earnings while maintaining its tradition of safe and dependable service to customers at reasonable cost. The directors also extend their warm appreciation to customers for their continuing support and suppliers for their conscientious service.

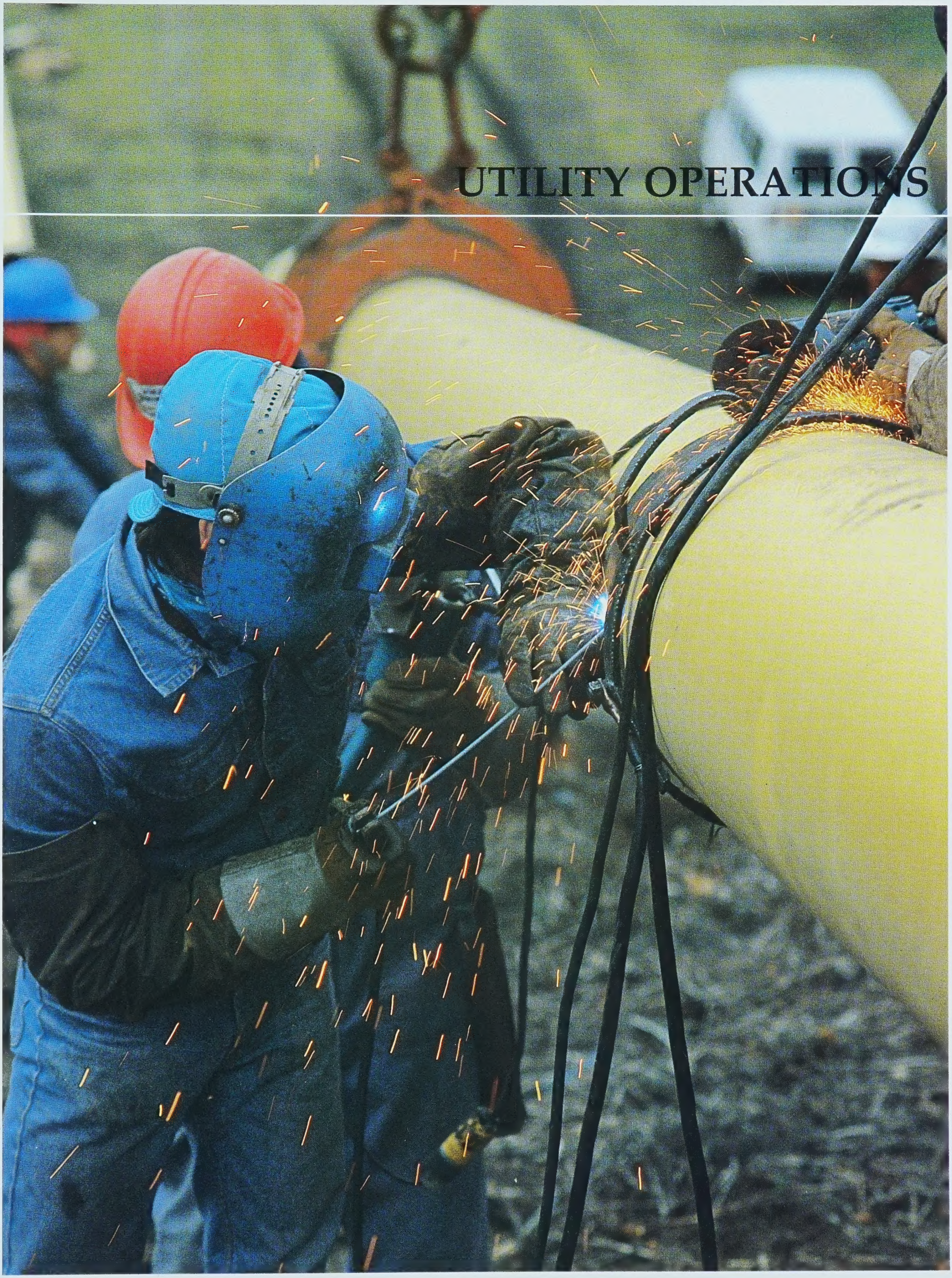
On behalf of the Board of Directors,

R. D. Southern,
Chairman and
Chief Executive Officer

J. D. Wood,
President and
Chief Operating Officer

March 11, 1985

UTILITY OPERATIONS



NATURAL GAS OPERATIONS

Canadian Utilities' natural gas operations are carried out by two utilities, Canadian Western Natural Gas Company Limited, which serves southern Alberta including Calgary and Lethbridge, and Northwestern Utilities Limited, which serves north-central Alberta including Edmonton, Red Deer, Fort McMurray, Grande Prairie and Camrose, as well as the Lloydminster area. A Northwestern Utilities subsidiary, Northland Utilities (B.C.) Limited, serves Dawson Creek and district and the community of Tumbler Ridge in north-eastern British Columbia.

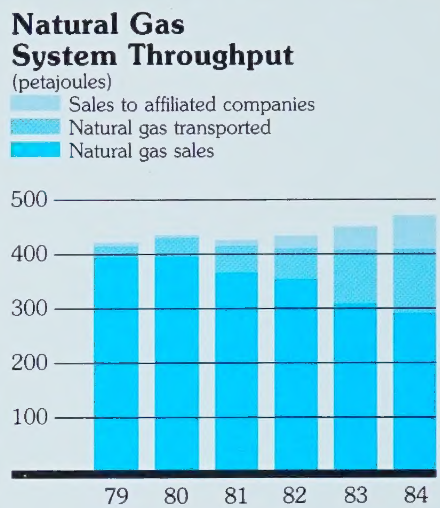
Natural gas operations achieved a modest 2.2% customer growth rate during 1984, adding 12,891 customers by year-end to raise the total number served to 593,558. The new customer number includes 5,586 added when Northwestern Utilities purchased all shares of The Lloydminster Gas Company Limited, which was subsequently amalgamated into Northwestern. Lloydminster Gas provided service to customers in the City of Lloydminster and the communities of Kitscoty and Blackfoot as well as some rural customers in Alberta and Saskatchewan.

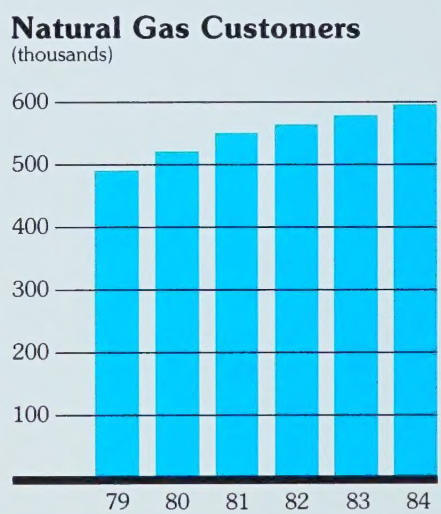
As the adverse economic environment continued to affect the natural gas service territories, new operational objectives were introduced and restraint measures affecting expenditures were tightened. Through these actions the gas utilities were able to achieve cost savings and improve productivity. Although customer growth continued during the year, the number of gas utility employees decreased from 2,528 to 2,438.

Staff covered under agreements with the Employee Associations received no pay increases during 1984. New two-year agreements were signed with the Associations early in 1985 providing the equivalent of a 3% pay raise for permanent employees in 1985 and provisions to negotiate salaries in the second year.

Earnings attributable to Class A and Class B shares from natural gas operations were $34.2 million compared to $26.2 million in 1983. Northwestern's earnings were favourably affected in the amount of $5.0 million by lower natural gas costs, principally due to adjustments by the Provincial Government of production gas cost allowances, and by the gain realized from the sale of non-utility assets. After taking into account the effects of weather and rate changes, gas operations earn-

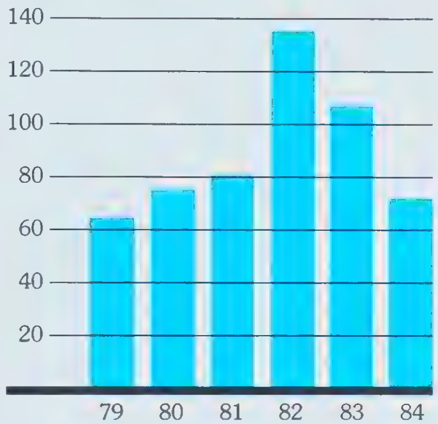
Engineering Division Manager Rob Armstrong and Northwestern's Vice-President and General Manager Graham Lock look over plans for the $36.2 million salt cavern natural gas peak storage facility near Fort Saskatchewan.



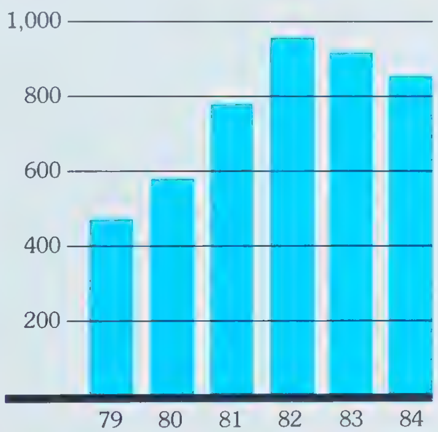


LEFT:
A Canadian Western customer serviceman installs a remote meter reader at a Calgary home. The device, which allows for increased convenience for customers, was introduced in 1983.

Capital Expenditures
(millions of dollars)

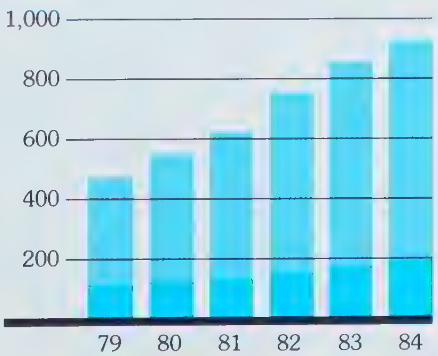


Natural Gas Revenues
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)

Property, plant and equipment — net
Accumulated depreciation



METRIC CONVERSION

This annual report contains operating statistics which are reported in metric units of measurement.

The metric unit for measurement of energy is the joule (J) and its multiples. Large amounts of energy will be reported in gigajoules (GJ), billions of joules; in terajoules (TJ), trillions of joules; and in petajoules (PJ), quadrillions of joules.

Imperial	Metric Equivalent
1 British Thermal Unit	1,054.615 joules
1 cubic foot (natural gas)	0.028317 cubic metres (m^3)
1 barrel (petroleum liquids)	0.159 cubic metres (m^3)

ings have been consistent with the rate of asset growth and changes in costs of capital.

RATE DEVELOPMENTS

Effective February 1, 1984 the Alberta Public Utilities Board approved reductions in rates. An increase in the cost of natural gas supply was more than offset by increased shielding through the Alberta Natural Gas Price Protection Plan and reduction of the Natural Gas and Gas Liquids Tax by the Federal Government.

In May, 1984 Northwestern filed an application with the Public Utilities Board to recover projected shortfalls in revenue for 1984 and 1985. The application for interim refundable rates to be effective June 1, 1984 was subsequently denied. Upon reviewing Northwestern's complete application in October, the Public Utilities Board approved an interim refundable rate increase, effective November 1, 1984. The decision allows Northwestern to collect $10.0 million of its 1984 revenue shortfall during the period November 1, 1984 to June 30, 1985 and $25.0 million for 1985 in that year. Approximately $5.0 million of the $10.0 million allowed was recorded in 1984. Northwestern had projected revenue shortfalls of $23.3

Canadian Western is helping to field-test vehicles designed to operate solely on natural gas. Canadian Western has been a leader in Canada in developing the technology of natural gas fueled vehicles.

Gas Operations Earnings Contribution

	1984	1983	1982	1981	1980	1979	Annual Growth Rate 1979-84
			(Millions of dollars)				%
Natural gas revenues	**861.2**	928.4	959.1	779.2	581.7	477.9	12.5
Operating expenses							
Natural gas supply	**517.3**	512.6	444.8	442.2	405.8	342.3	8.6
Operation and maintenance	**117.1**	114.2	107.6	86.4	73.3	61.1	13.9
Taxes — other than income	**97.9**	207.3	306.2	185.6	47.1	23.4	33.1
Taxes — income	**36.4**	24.2	21.8	9.3	7.6	9.2	31.7
Depreciation	**22.9**	17.2	17.1	13.9	11.9	10.3	17.3
	791.6	875.5	897.5	737.4	545.7	446.3	12.1
	69.6	52.9	61.6	41.8	36.0	31.6	17.1
Other deductions — net	**35.4**	26.7	28.6	20.3	18.4	13.5	21.3
Earnings attributable to Class A and Class B shares	**34.2**	26.2	33.0	21.5	17.6	18.1	13.6
Mid-year common equity investment	**183.2**	171.8	145.2	117.9	109.2	100.3	12.8

million in 1984 and $42.5 million in 1985. A final decision on the application is expected during 1985.

The British Columbia Utilities Commission acted expeditiously to change the rates of Northland Utilities (B.C.) Limited on February 1, 1984 and August 1, 1984. In February, rates were reduced as the Natural Gas and Gas Liquids Tax was reduced, partially offset by an increase in gas costs. Rates were increased in August due to an increase in the wholesale cost of gas in British Columbia.

Canadian Western was able to avoid a rate increase application in 1984.

NATURAL GAS THROUGHPUT

The combined total of natural gas sold and transported was 470.5 petajoules (PJ), up from 450.9 PJ in 1983. Both gas utilities transport gas within Alberta for exporting companies for delivery to the NOVA system and for industrial and other customers who have contracted for their gas supplies directly with brokers or producers. Sales and transportation for industrial customers increased by 6.1 PJ resulting mainly from an increase of 27.5 PJ for petrochemical and refinery customers offset by a 10.0 PJ reduction in demand for gas-fired power generation. Another offsetting factor was a 10.1 PJ decrease in sales to a customer in the fertilizer sector who took less than the minimum annual volume of natural gas it had contracted to take from Canadian Western.

Transportation of natural gas for exporting companies increased by 5.3 PJ. In addition, sales to residential and commercial customers increased by 7.9 PJ due to colder temperatures than in 1983.

The table below shows natural gas sales to various categories of customers, plus natural gas transported for exporting companies and industrial customers.

Natural Gas Sales and Transportation

	Terajoules	% of Total
Sales		
Industrial	99,623	21.2
Commercial	89,756	19.1
Residential	87,453	18.6
Other	9,136	1.9
	285,968	**60.8**
Transportation	123,843	26.3
	409,811	**87.1**
Sales and transportation - affiliates	60,694	12.9
Total system throughput	**470,505**	**100.0**

In terms of degree days — a measure of space heating requirements — 1984 was comparable to 1983 for

LEFT:
Grass seed and fertilizer are broadcast along the right-of-way for the Tumbler Ridge transmission line to restore the land to its natural state. The conversion of residential customers in Tumbler Ridge to natural gas took place in February.

Northwestern as both years were 4% warmer than normal. For Canadian Western 1984 was 4.6% warmer than normal, while 1983 was 5.9% warmer than normal.

An increase in sales resulting from growth in customers in the residential and commercial market sectors was largely offset by a decline in sales per customer due to increased energy conservation.

REVENUES, COSTS AND TAXES

Revenues from natural gas operations for 1984 were $861.2 million, $67.2 million lower than in 1983. This decrease was attributable to reductions in the Federal Natural Gas and Gas Liquids Tax and lower sales to power plants and other industrial customers. Also, the substitution of transportation service for sales to industrial customers resulted in lower revenue. Total operating expenses, which include the cost of natural gas supply, operations, maintenance, taxes other than income, income taxes and depreciation, amounted to $791.6 million, down $83.9 million from 1983.

Natural gas supply costs increased by $4.7 million to $517.3 million net of rebates. Rebates of $102.8 million received from the Alberta Government under the Natural Gas Rebates Act shielded eligible Alberta consumers from the full cost of natural gas purchased. Rebates totalled $91.4 million in 1983.

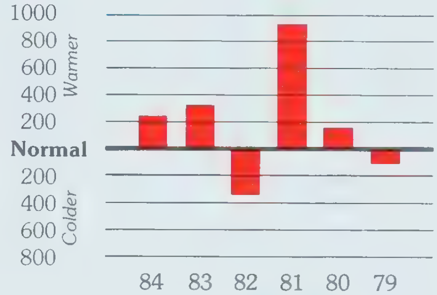
Total taxes paid to all levels of government decreased $97.2 million to $134.3 million in 1984, and amounted to 15.6% of total revenue compared to 24.9% in 1983. Federal taxes resulting from the National Energy Program amounted to $44.5 million, a decrease of $108.8 million from 1983.

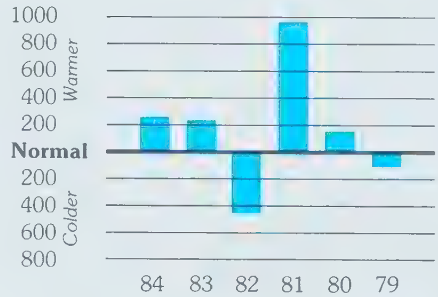
World oil prices remained relatively stable during 1984. Accordingly, to maintain the price differential between oil and natural gas at the Toronto gate, the Natural Gas and Gas Liquids Tax was reduced on

DEGREE DAYS

Calgary

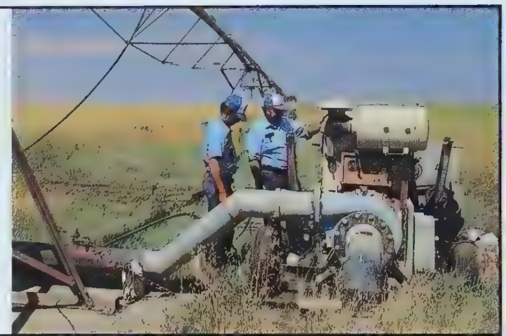
Edmonton





DEGREE DAYS: The number of degrees by which daily mean temperature falls below 18 degrees C. One degree day is counted for each degree of deficiency for each day on which such a deficiency occurs. For example, if the mean temperature for a day was 10 degrees C, then there are eight degree days during the 24-hour period.

Canadian Western Natural Gas and Northwestern Utilities sell natural gas appliances through company retail outlets. Below is Canadian Western's appliance sales centre in Calgary.



Canadian Western technicians make adjustments to one of many natural gas fueled engines used extensively in the Lethbridge area to power equipment for more than 2,300 irrigation customers.

February 1, 1984 coincident with the scheduled increase in the Alberta border price. Northwestern and Canadian Western continue to pay the Federal Canadian Ownership Tax of 14¢ per gigajoule (GJ). The Petroleum and Natural Gas Revenue Tax on net production revenue remained at 12% during 1984.

Property and franchise taxes paid to municipalities were $52.2 million, of which $20.6 million was paid to the City of Calgary and $18.1 million to the City of Edmonton. Provincial mineral taxes decreased from $1.9 million to $1.2 million in 1984 due to reduced production from Company owned reserves.

CAPITAL EXPENDITURES

Gas operations capital additions to provide for customer growth and meet the needs of existing customers were $72.9 million. Net property, plant and equipment required to serve customers increased to $731.2 million at year-end. During 1984, the Public Utilities Board approved the sale of certain non-utility oil properties to an affiliated company.

During 1984 Northwestern commissioned two of the five salt caverns under development near Fort Saskatchewan, Alberta. These caverns and related gas handling facilities are available to meet customers' peak demand requirements. The project is the most cost-effective method of meeting current peaking requirements. Total cost of the first five caverns is estimated at $36.2 million.

Also, construction was completed on Northwestern's $3.2 million transmission line to loop the Esso Lateral. This line serves the Shell Scotford refinery, Shell styrene plant and connects the existing Esso chemical lateral to the new salt cavern facilities.

In the new coal mining community of Tumbler Ridge served by Northland Utilities (B.C.) Limited, 659 new customers were added and by year-end 1,206 customers in the community were served with natural gas. Gas processing and transmission facilities required to serve Tumbler Ridge were commissioned in 1984.

During 1985, Northwestern and Canadian Western will continue to seek opportunities to profit from growth within their service territories. Although only moderate growth is expected in the near term, the utilities are well positioned to participate in the benefits from the construction and administration of energy related projects proposed for the areas of Cold Lake, Lloydminster, Fort McMurray and Peace River.

ELECTRIC POWER OPERATIONS

Canadian Utilities' major electric power utility, Alberta Power Limited, serves 373 communities in east-central and northern Alberta and two communities in Saskatchewan. Alberta Power's subsidiary companies, The Yukon Electrical Company Limited and Northland Utilities (NWT) Limited, serve 18 communities in the Yukon, one community in British Columbia and five communities in the Northwest Territories. Another subsidiary, Yukon Hydro Company Limited, operates two small hydro-electric plants in the Yukon.

Energy sales to retail customers in 1984 increased by 7.3% to 3,882 million kilowatt hours. In addition, 1,104 million kilowatt hours were sold to the City of Edmonton under a unit power agreement and 161 million kilowatt hours were sold to Edmonton and TransAlta Utilities Corporation under a Province-wide system of economic dispatch.

During 1984, 3,511 retail customers were added, bringing the year-end total to 143,401. Included in this number were 26,099 farm customers of whom 16,648 are members of 105 Rural Electrification Associations. During 1984, 14 Rural Electrification Associations comprising 1,544 members voted to sell their distribution systems to Alberta Power.

The peak load created by Alberta Power's retail customers increased to 741 megawatts in 1984 from 720 megawatts the previous year.

The following table shows 1984 electric sales to the various customer groups (excluding sales to other utilities):

	Thousands of Kilowatt Hours	% of Total
Industrial	2,094,291	54.0
Commercial	729,363	18.8
Residential	657,740	16.9
Other	400,859	10.3
	3,882,253	**100.0**

Along with other companies and individuals in its service area who were affected by the recession, Alberta Power maintained restraint measures, first implemented during 1982, on both operating and capital expenditures.

Hiring and overtime were restricted with the result that, although the number of customers increased, permanent staff declined from 1,321 to 1,314 employees. Travel and training were reduced, and staff not included within the scope of the Employees' Association agreement received salary increases in 1983 and 1984 consistent with the Federal guidelines. Staff covered under the agreement with the Employees' Association received no pay increase during 1984. A further two-year agreement with the Association was signed late in 1984 providing a 3% pay raise in 1985 and provision to negotiate salaries in the second year of the agreement.

Earnings attributable to Class A and Class B shares were $62.9 million compared to $61.3 million in the previous year.

Alberta Power serves a number of large industrial power consumers in the north and east-central parts of Alberta, including the Husky refinery at Lloydminster.

REGULATORY ACTIVITY

Alberta Power made no application to the Public Utilities Board of Alberta to increase its retail rates during 1984, seeking instead to attempt to earn its allowed return with rates that had been approved by the Board in 1983, through continuing application of restraint measures and achievement of productivity gains wherever possible. Moreover, Alberta Power did not apply to the Public Utilities Board for a change in its price of energy sold to the Electric Energy Marketing Agency and was able to maintain a rebate of 21% to its customers through the Agency's averaging process.

On November 13, 1984 the Electric Energy Marketing Act was amended whereby, effective January 1, 1985,

LEFT:
Keeping electric costs low while ensuring a reliable supply of energy is the purpose of the Alberta interconnected system, which takes all electricity generated in the Province to where it is needed. Co-ordination of facilities is provided through control centres like this one in Alberta Power's Grande Prairie office.

Alberta Power would sell to the Agency energy at 3 prices in respect of residential-farm, large industrial and general service customer groups, and repurchase the energy at 3 average prices. These prices will remain fixed for a year, but then may be the subject of a retrospective hearing by the Public Utilities Board, which may issue an adjustment order. The Public Utilities Board Act has been amended to permit automatic adjustments to retail rates in respect of these adjustment orders.

On January 17, 1985 the Public Utilities Board issued an order instructing Alberta Power to file a submission for a general rate proceeding covering the 1984 and 1985 test years, and to file an application for a price for the sale of energy to the Marketing Agency covering 1984.

CONSTRUCTION PROJECTS

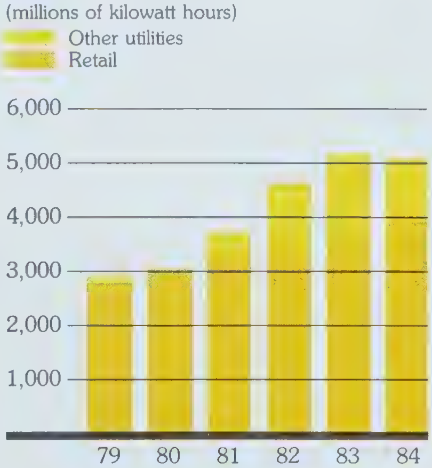
Alberta Power's expenditures for additions to property, plant and equipment during the year were $147.7 million. The largest single amount, $91.6 million, was spent on the 750-megawatt Sheerness Generating Station and related mining facilities, a joint project with TransAlta Utilities.

Expenditures on transmission projects during the year totalled $25.5 million. Major projects included a 103-kilometre 240-kilovolt line from Louise Creek to Mitsue; a 27-kilometre 144-kilovolt line from Bonnyville to Ethel Lake; a 46-kilometre 144-kilovolt line from Flyingshot to Beaverlodge; a 12-kilometre 144-kilovolt line from Beaverlodge to Elmworth; and the third phase of the Anderson sub-station, which is being constructed at the site of the Sheerness Generating Station.

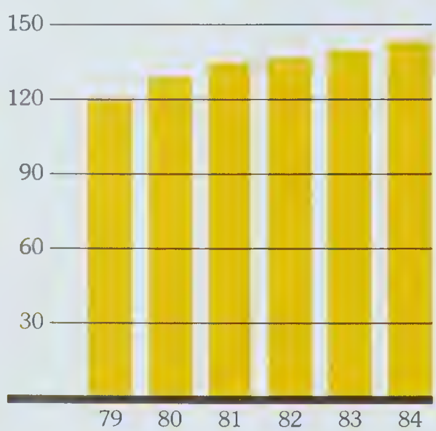
Other major transmission projects that are currently planned or under way include a 48-kilometre 144-kilovolt line from Rycroft to Ksituan River; a 45-kilometre 144-kilovolt line from Clairmont Lake to Wembley; an 18-kilometre 144-kilovolt line from Louise Creek to Judy Creek; a static var compensator at Bonnyville; 220 kilometres of 144-kilovolt transmission lines to serve in situ oil production projects in the Cold

Alberta Power's servicemen are a mobile force ready to ensure that customers have electric energy when and where they need it under all weather conditions.

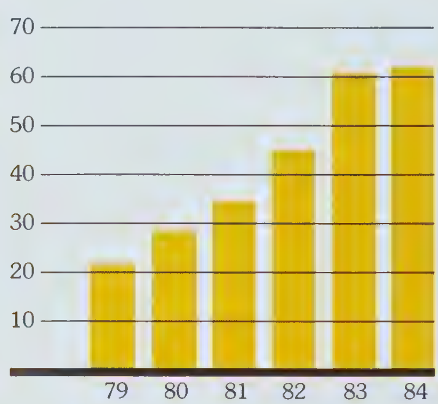
Electric Sales
(millions of kilowatt hours)



Electric Customers
(thousands)



Earnings Attributable to Class A and Class B Shares
(millions of dollars)

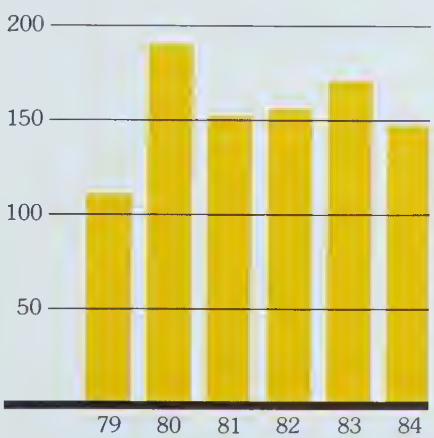


BELOW:
Construction of Unit 1 of the Sheerness Generating Station near Hanna, Alberta was essentially completed by the end of 1984. The conveyor belt shown here will carry the 250 tonnes of coal the Unit will require each hour of full operation.

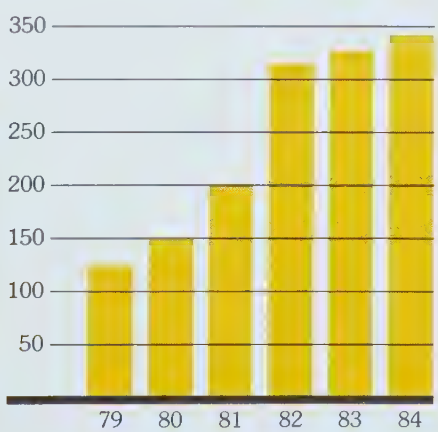
Electric Operations Earnings Contribution

	1984	1983	1982	1981	1980	1979	Annual Growth Rate 1979-84
			(Millions of dollars)				%
Electric revenues	**340.3**	327.2	316.3	201.7	149.8	124.6	22.3
Operating expenses							
Operation and maintenance	**128.7**	122.3	131.4	93.7	74.4	61.7	15.8
Taxes — other than income	**12.5**	12.3	9.9	7.2	5.1	4.5	22.7
Taxes — income	**60.4**	58.2	56.0	17.8	11.8	6.7	55.2
Depreciation	**34.1**	31.8	29.8	20.9	16.0	14.6	18.5
	235.7	224.6	227.1	139.6	107.3	87.5	21.9
	104.6	102.6	89.2	62.1	42.5	37.1	23.0
Other deductions — net	**41.7**	41.3	43.6	27.2	13.2	15.4	22.0
Earnings attributable to Class A and Class B shares	**62.9**	61.3	45.6	34.9	29.3	21.7	23.7
Mid-year common equity investment	**323.7**	293.7	243.1	198.5	181.3	149.7	16.7

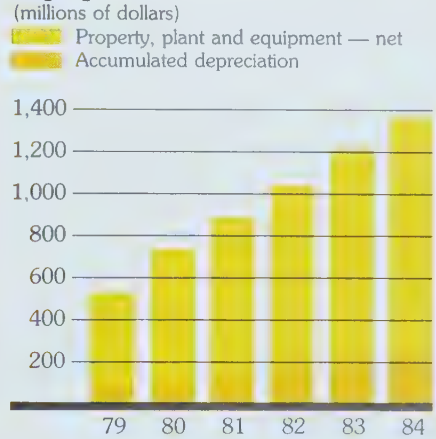
Capital Expenditures
(millions of dollars)



Electric Revenues
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)



OPPOSITE:
Gulf's drilling vessel the "Kulluk" tests oil at the East Amauligak J-44 discovery well in the Beaufort Sea. AT&S holds an interest of approximately 3% in the well.

Lake area; and a 28-kilometre 144-kilovolt line from Michichi Creek to Carbon.

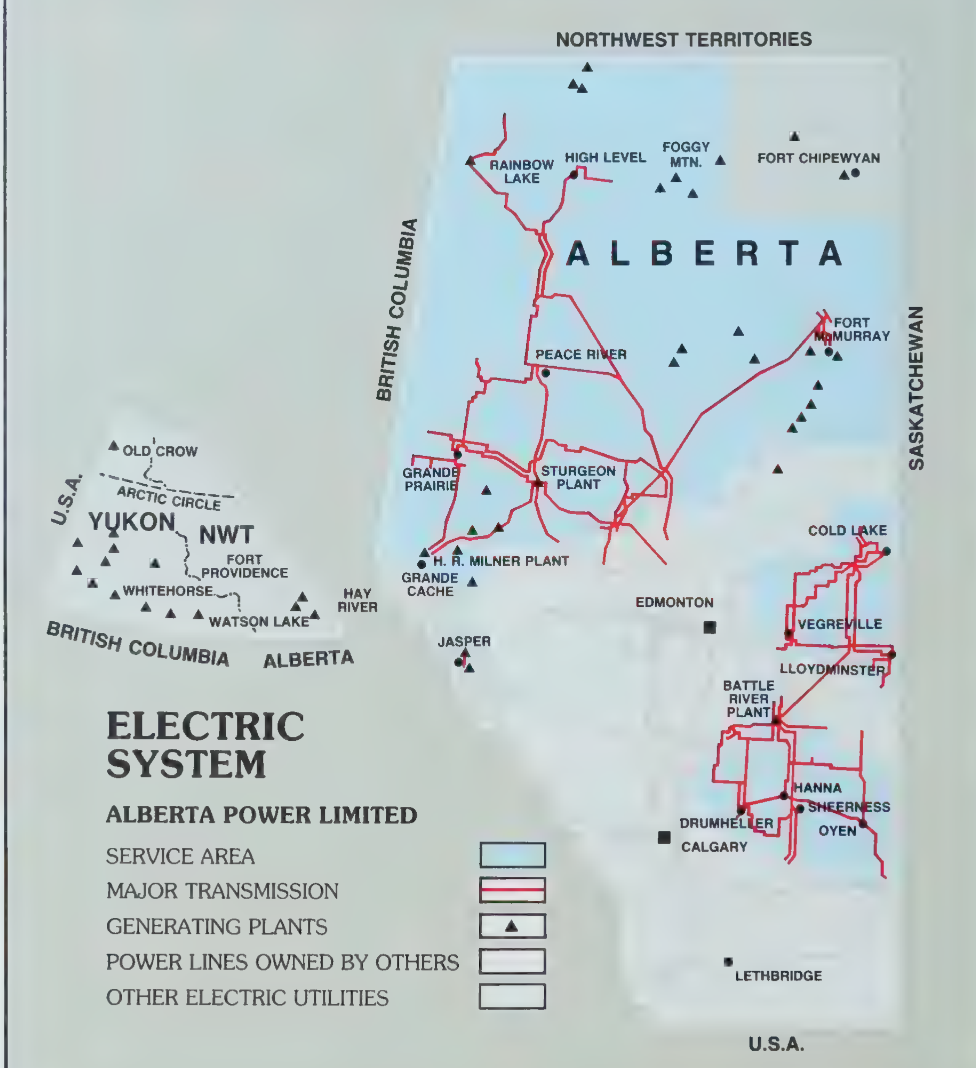
FUTURE DEVELOPMENTS

In July 1984, the Electric Utility Planning Council produced its annual forecast of Alberta's energy requirements for the years 1984 to 2008. As a result, the Energy Resources Conservation Board (ERCB) called a public hearing in January 1985 to consider any amendments to the commissioning dates and sequence of generating unit additions which the Provincial Cabinet had approved in February 1984. Alberta Power argued before the Board that Sheerness Unit 1 should be commissioned in January 1986 as originally approved, but that Sheerness Unit 2 and Genesee Units 2 and 1 should be deferred from 1987, 1988 and 1989 to 1990, 1990 and 1991 respectively. A decision is pending from the ERCB.

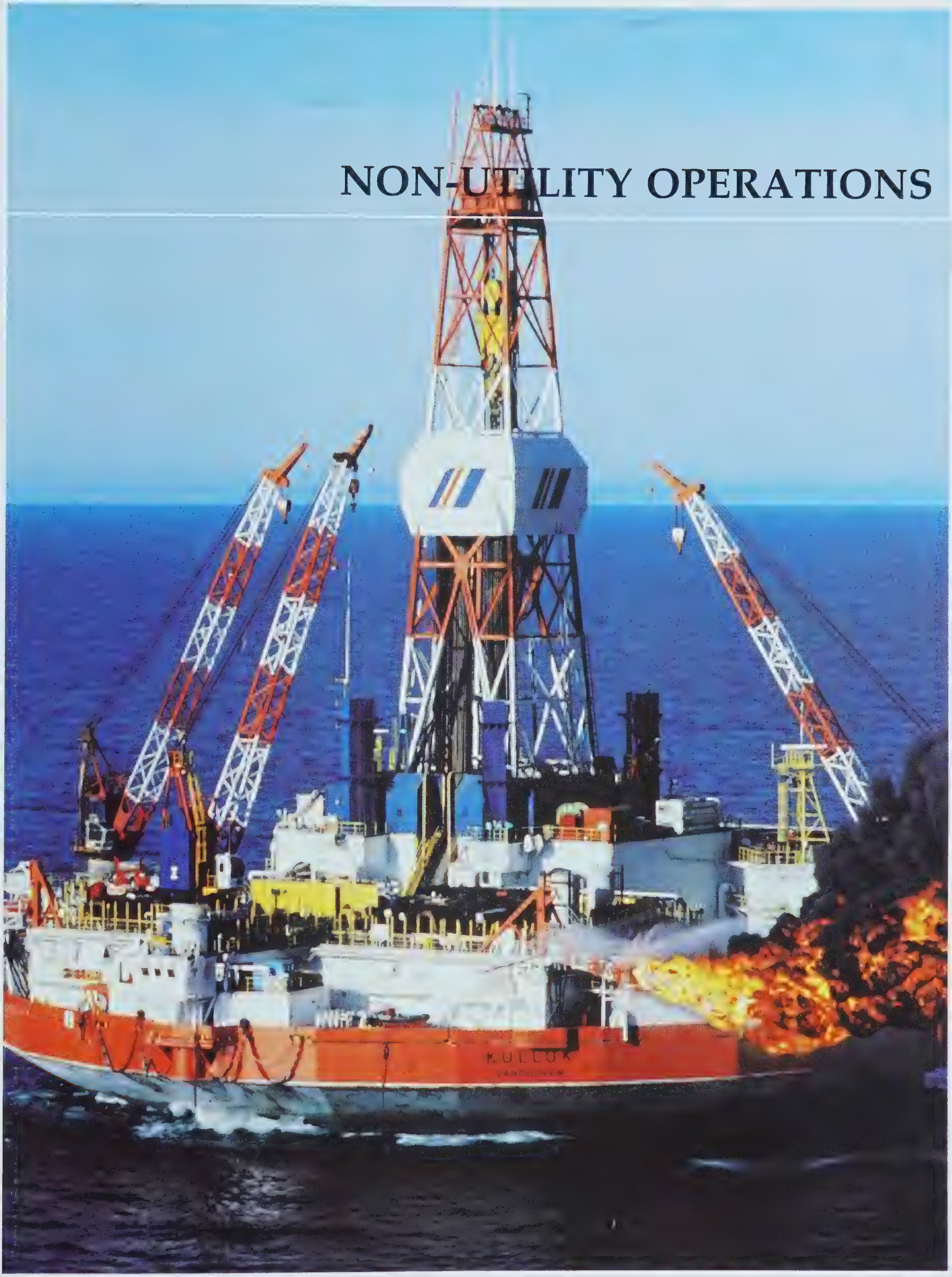
Little work was carried out on the pre-investment study of the proposed hydroelectric project on the Slave River, pending a decision on the feasibility study completed during the year.

During the year the ERCB approved the allocation of most of the previously unallocated area within the Province (excluding Federal parks) between Alberta Power and TransAlta Utilities. APL now serves 55.8% of the allocated service area in the Province.

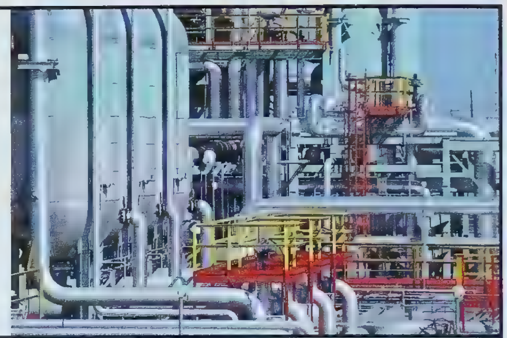
Harvey Kerslake (left), Supervising Resident Engineer at the Sheerness Generating Station construction site, works with Site Manager Ray Prouse, as Unit 1 nears completion. During 1985, all parts of the Unit will be tested to ensure it is ready to begin producing electricity, as currently scheduled, in January 1986.



NON-UTILITY OPERATIONS



NON-UTILITY OPERATIONS



ATCOR Resources Limited, the Company's non-utility energy subsidiary, has experienced its most successful year in earnings and cash flow since its formation in 1982.

FINANCIAL HIGHLIGHTS — 1984

- Revenues from the sale of products and services increased 29.4% from $130.8 million to $169.3 million including sales to affiliated companies of $7.1 million compared to $7.2 million last year.
- Earnings before income taxes rose from $16.1 million to $18.7 million, an increase of 16.1%.
- Cash flow from operations increased from $18.1 million to $21.9 million, an increase of 21.0%.
- Net earnings rose $2.1 million to $9.1 million, an increase of 30.0%.
- Total assets increased from $126.1 million to $136.1 million, up 7.9%.
- Oil and gas reserves were independently valued at $83.4 million at a 15% discount rate.

ATCOR is well positioned, both financially and operationally, to pursue oil and gas exploration, development, processing and marketing opportunities in Canada during the coming years.

PROCESSING AND MARKETING

ATCOR owns a 50% interest in an ethane extraction plant located in south Edmonton. The plant processed a daily average of 5.9 million cubic metres of natural gas resulting in a daily average recovery of 651 cubic metres of ethane and 200 cubic metres of LPGs (propane, butanes and pentanes plus) for ATCOR's account.

The south Edmonton plant has the capacity to process 8.9 million cubic metres of natural gas per day. Since start-up in 1978, the plant has operated below capacity. In 1984, the plant owners reached an agreement to process for a fee additional volumes of gas over the next 7 to 10 years. The ethane and LPGs recovered from this gas stream will be returned to the customer. The processing fee provides the plant owners a profit margin in excess of that available from processing alternative gas supplies. At full production rates from this contract the plant will operate near capacity levels. Plant modifications required to process the additional gas volumes will be completed by the summer of 1985.

Commencing in November 1984 and continuing during the peak winter months, the plant owners have assumed responsibility for supplying all natural gas make-up to the plant. The make-up gas was previously supplied by Northwestern Utilities Limited. Over the next five years that responsibility will expand to cover the entire year. This new natural gas market provides ATCOR with the opportunity to expand and develop its natural gas production and company-owned reserve base.

ATCOR also markets natural gas to large industrial customers for use as fuel and feedstock and to resource companies for use in enhanced oil recovery projects. During 1984, ATCOR delivered 76 petajoules of natural gas to 16 customers. The gas was supplied by 42 producing companies under 86 separate supply contracts.

CARBON-JOFFRE NGL PROJECT

ATCOR is developing plans to build two natural gas liquids recovery plants in the Carbon and Joffre areas of east-central Alberta. The liquids extracted at Carbon will be transported by pipeline to Joffre where they will be fractionated along with liquids extracted at Joffre. The Joffre plant will produce a high quality ethane product and a propane-plus mixture. Capital costs for the entire project will be about $35 million.

Throughout 1985, ATCOR will be seeking necessary government approvals and attempting to obtain sales contracts for the plant products. Should ATCOR be successful in these activities, a decision to proceed with the project will be forthcoming. Construction of the plants and related facilities could begin by the summer of 1985.

EXPLORATION AND PRODUCTION

ATCOR's exploration activities are concentrated in western Canada. During the year, a total of 102 wells were drilled jointly with others resulting in 48 oil wells, 22 gas wells and 32 unsuccessful wells. ATCOR continues to increase its net working interest in drilling programs over prior years in order to be more effective with the limited technical resources available to it. This is a continuing objective of ATCOR's management.

ATCOR spent $22.3 million on exploration and development activities excluding its investment in AT&S Exploration Ltd. (AT&S). Spending in 1985 and 1986 is expected to be $20.0 and $27.0 million respectively, allocated prima-

ATCOR Resources Limited is a 50% owner of this ethane extraction plant in south Edmonton. ATCOR is developing plans to build two natural gas liquids recovery plants in the Carbon and Joffre areas of east-central Alberta.

rily to western Canada. With crude oil and natural gas prices expected to remain stable in the near future, success depends on finding hydrocarbon reserves at costs which provide for adequate returns without price increases.

Sales of crude oil accounted for more than 80% of hydrocarbon sales. Oil production averaged 260 cubic metres per day (194 cubic metres per day net). Natural gas production averaged 125,128 cubic metres per day (91,334 cubic metres per day net). It is ATCOR's intention to increase its natural gas reserves and production in the coming years at a higher growth rate than that of its oil reserves and production. To achieve this objective, ATCOR has allocated more than 60% of its exploration and development budget in 1985 and 1986 to the search for economic reserves of natural gas.

ATCOR purchased the producing and non-producing petroleum rights on lands held by Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited. This acquisition provides ATCOR with additional development opportunities.

At the end of 1984, crude oil and natural gas reserves were as follows:

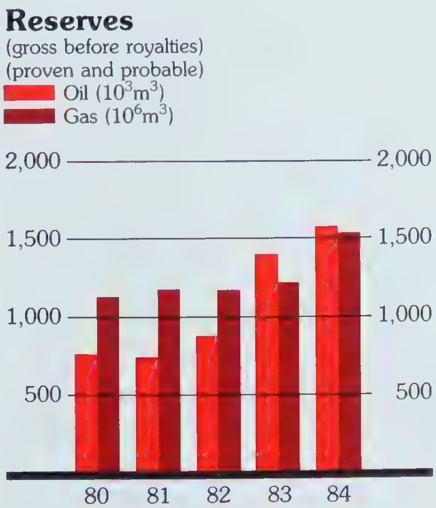
	Gross Before Royalties		
	Proven	Probable	Total
Crude Oil and Gas Liquids (10^3m^3)			
1984	751	826	1,577
1983	630	778	1,408
Natural Gas (10^6m^3)			
1984	1,101	434	1,535
1983	874	350	1,224

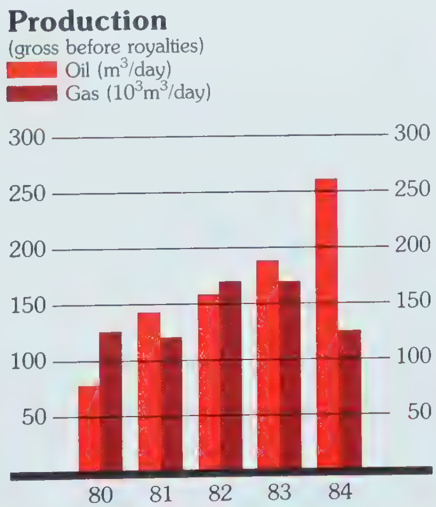
Petroleum and natural gas rights held at year-end were as follows:

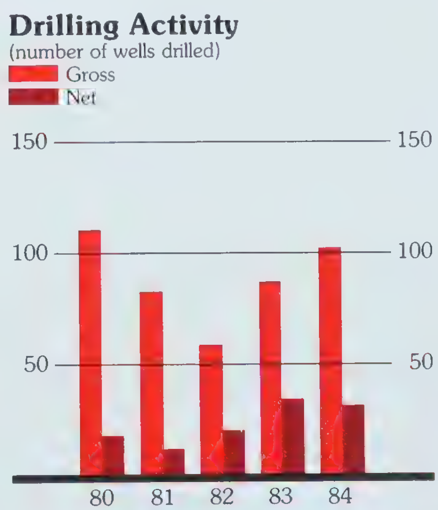
	Hectares	
	Gross	Net
Alberta	221,334	59,613
Saskatchewan	16,955	6,864
British Columbia	4,670	1,124
Manitoba	4,903	1,504
	247,862	69,105
Petroleum rights only (Alberta)	354,501	174,220
	602,363	243,325

AT&S EXPLORATION LTD. (AT&S)

AT&S, a joint exploration company, commenced operations in September 1983. ATCOR owns 30% of the outstanding common shares of AT&S. Its objectives are to find oil and natural gas on Canada Lands and establish preferred acreage positions during the life of the Petroleum Incentive Program. Participating in selected exploration activi-







OPPOSITE:
The massive turbine for Unit 1 at Sheerness was installed in 1984.

ties with a minority working interest, AT&S has earned or holds rights to earn interests in over 5.6 million gross hectares. By year-end AT&S had participated in the drilling of two oil discoveries and one dry hole with six additional wells in various stages of drilling and testing. It is projected by the end of 1986, AT&S will have participated in the drilling of at least 36 wells.

AT&S is participating in the Esso-Home, MacKenzie Delta, Beaufort Sea group through a farmin with Canalands Resources Corporation. AT&S will earn an interest in past earned lands and discoveries such as West Atkinson, Itiyok, Kadluk and Tuk, and an interest in all future earned land and wells, by investing the funds required to meet Canalands commitments. The interest earned will be determined upon completion of the program and will be proportionate to the investments made by each company.

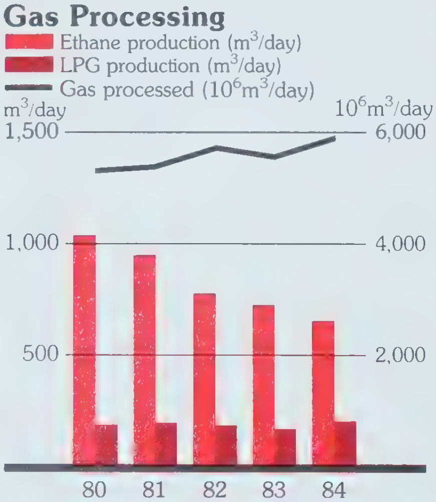
AT&S has also participated in a farmin for the drilling of the Gulf East Amauligak significant oil discovery and in the drilling of the Gulf Tarsuit P-45 marginal oil discovery.

AT&S will earn a 10% interest from Esso Resources Canada Limited in their Flemish Pass Prospect offshore Newfoundland. Flemish Pass is adjacent to the Avalon Basin which contains the prolific Hibernia oil pools. The first well on this prospect will be drilled in the next 12 months.

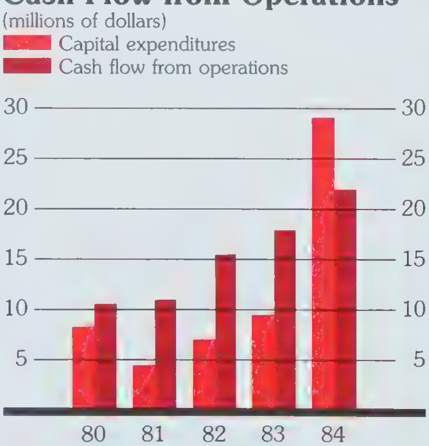
Under farmin agreements with Texaco Canada Resources Ltd., a dry hole was drilled in the Banquereau Block of acreage offshore Nova Scotia and a second well is currently drilling. AT&S will earn 15% interest in 39,353 hectares upon completion of these two wells. Further interests would be available if a third well is drilled. At West Venture near Sable Island, AT&S is participating in two wells, which could result in the extension of the Venture Field, and will earn a 9% interest in 36,367 hectares upon completion of both wells.

AT&S is also drilling two exploratory wells in the Norman Wells area of the Northwest Territories to earn a 50% interest in 18,826 hectares. The first well has been drilled and cased and will be tested for potential hydrocarbons. The second well is drilling and will be completed prior to spring breakup. In addition, AT&S is participating in a well in the Keele River area south of Fort Norman.

Gas Processing

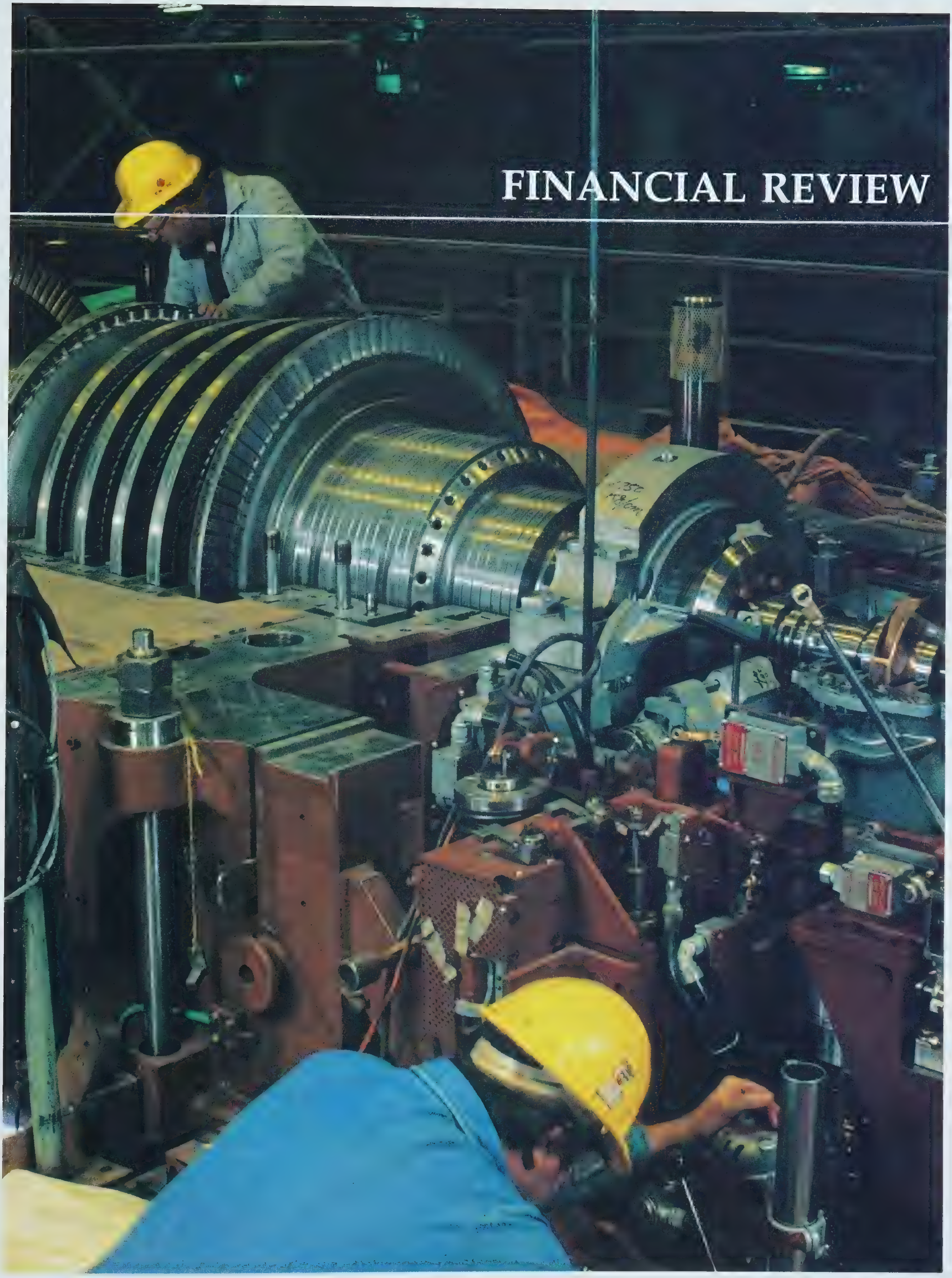


Capital Expenditures and Cash Flow from Operations



BELOW:
A supervisor inspects the hydraulic drive and rotary head unit on a heavy oil well near Maidstone, Saskatchewan. ATCOR Resources Limited developed this type of wellhead assembly in conjunction with an Edmonton manufacturer to improve operation of the screw-type pump ATCOR is using on heavy oil wells.

FINANCIAL REVIEW



FINANCIAL REVIEW

Gross revenues from outside customers in 1984 amounted to $1.364 billion compared to $1.380 billion the previous year. This decrease resulted from lower revenues in natural gas utility operations where 1984 revenues were $861.2 million compared to $928.4 million in 1983. These lower revenues were attributable to reductions in the Federal Natural Gas and Gas Liquids Tax collected in natural gas rates and to lower sales to industrial customers. In addition, the substitution of transportation service for sales to industrial customers resulted in lower revenues. The impact of these factors more than offset the increases in residential and commercial revenues for natural gas utility operations.

Revenues in electric utility operations were $340.3 million, up from $327.2 million in 1983, an increase of $13.1 million. The increase was due to higher retail electric energy sales in industrial and commercial markets.

Revenues in ATCOR Resources Limited totalled $162.2 million, an increase of $38.6 million over the $123.6 million reported in 1983. The increase was the result of larger gas volumes in gas marketing operations, and to a lesser degree, higher exploration and production revenues due to greater oil production and increased wellhead prices.

Earnings attributable to Class A non-voting and Class B common shares reached a record $101.4 million ($1.87 per share) in 1984, compared to $87.1 million ($1.62 per share), for the previous year. Weather in Alberta can have a significant impact on earnings in the Company's natural gas utility operations and to a lesser extent in the electric utility operations. Temperatures were about 4.3% warmer than normal in 1984, approximately equal to that of the previous year. The Company's utility operations grew in conjunction with investment growth in utility assets, and together with the introduction of operational objectives to achieve cost savings, produced favourable increases in earnings. When combined with a strong performance in the non-utility sector, total corporate earnings grew by 16.4% over 1983.

Earnings per Class A and Class B share

	1984	1983	Change
	$	$	$
Electric	**1.16**	1.14	.02
Natural Gas	**.63**	.49	.14
Non-Utility — Energy	**.14**	.10	.04
— Other	**(.06)**	(.11)	.05
	1.87	1.62	.25

The increase in earnings contribution from ATCOR Resources was the result of higher returns in gas marketing operations due to greater gas volumes combined with increased oil production and wellhead prices in production and exploration operations.

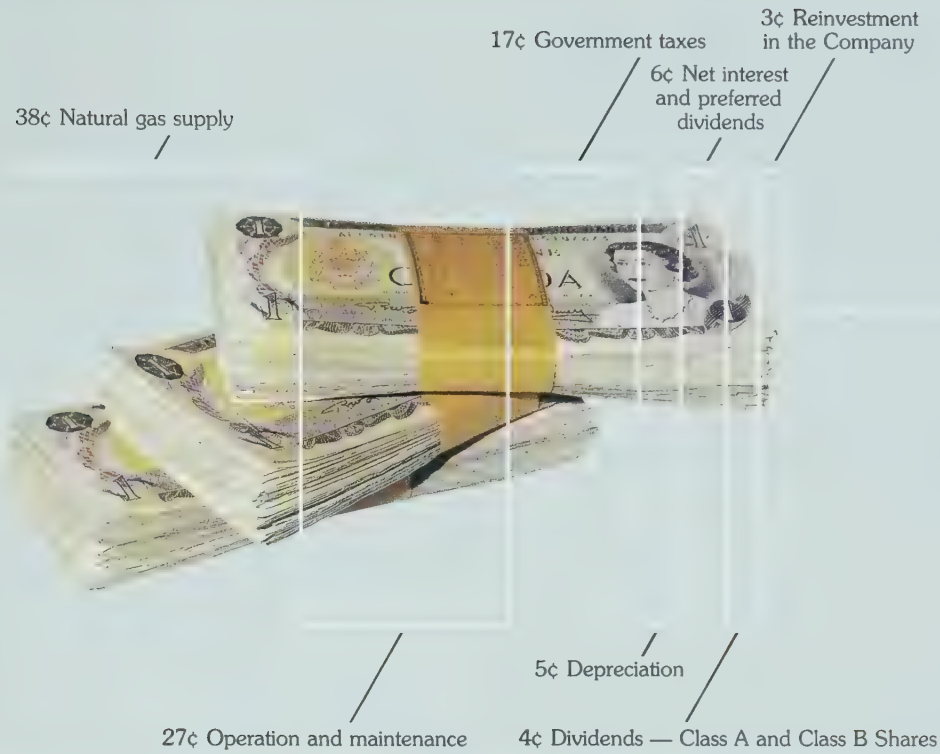
In non-utility other operations, the net carrying cost on the TransAlta Utilities investment improved in 1984 due to increased dividends on the TransAlta shares.

At the conclusion of 1984, there were 27,584,445 Class A non-voting and 26,627,129 Class B common shares outstanding for a total of 54,211,574. This total number of shares outstanding remained unchanged from December 31, 1983 as no new issues of shares were sold during the year. The Class A shares were distributed among 8,854 shareholders of whom 8,806 were Canadian residents. The Class B shares were held by 2,049 shareholders of whom 2,025 were Canadian residents. The total shares held by non-residents represented less than 1% of the total shares outstanding. During the year, 253,421 Class B shares were exchanged for an equal number of Class A shares. A more detailed explanation of the rights and privileges accorded these two classes of shares is contained in the notes to the consolidated financial statements. The Company's shares are listed on the Toronto, Montreal and Alberta stock exchanges.

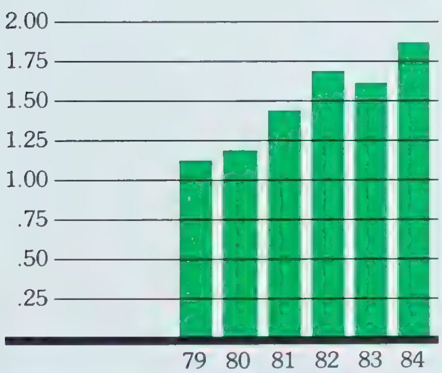
In 1984 the Company's quarterly dividend rate amounted to 26¢ per share in each of the first 3 quarters and was increased to 30¢ in the fourth quarter. The annual dividend of $1.08 in 1984 represented 58% of the $1.87 earnings per share in 1984.

Capital expenditures in 1984 amounted to $242.5 million. The Company's net investment in property, plant and equipment rose $174.3 million to $1.962 billion for the year. During the year, construction continued on the Sheerness Generating Station under a revised

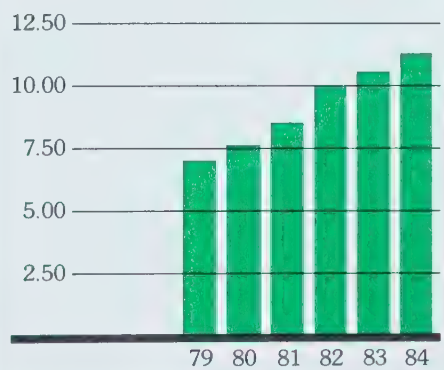
WHERE THE REVENUE DOLLAR WAS SPENT



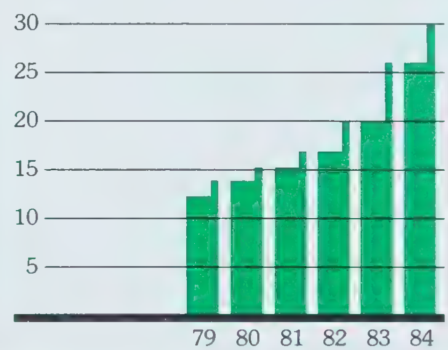
Earnings per Class A and Class B Share
(in dollars)
Annual Growth Rate 10.8%



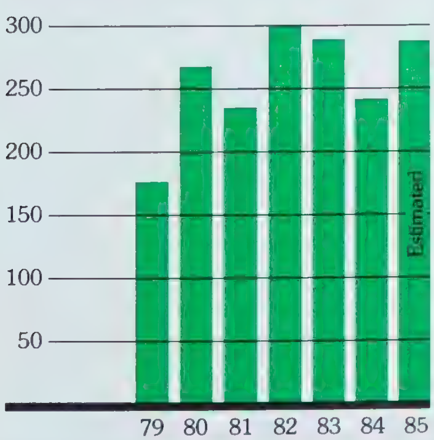
Equity per Class A and Class B Share
(in dollars)
Annual Growth Rate 10.2%



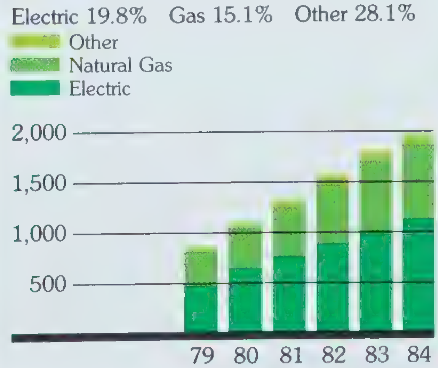
Dividends per Class A and Class B Share
(quarterly rate in cents)
Annual Growth Rate 16.3%
(1st quarter 1979 to 4th quarter 1984)



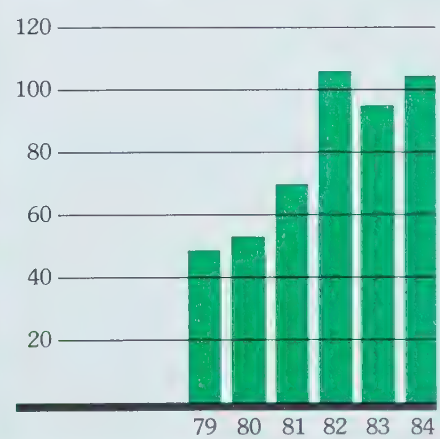
Capital Expenditures
(millions of dollars)



Property, Plant and Equipment — net By Type of Business
(millions of dollars)
Annual Growth Rate Total
Electric 19.8% Gas 15.1% Other 28.1%



Funds Provided Internally
(millions of dollars)



OPPOSITE:
A Northland Utilities (B.C.) employee checks a pressure gauge on the pipe rack at the Tumbler Ridge gas processing plant. This is the only sour gas sweetening plant in the Northwestern Utilities system.

completion schedule. The new timetable reflected Alberta Power Limited's application to delay commissioning of Unit 1 of the Sheerness plant by 6 months to January 1986, and Unit 2 by one year to July 1987. The Alberta Energy Resources Conservation Board approved the application on December 16, 1983 and the decision was subsequently upheld on February 22, 1984 by the Alberta Provincial Cabinet. Alberta Power and TransAlta Utilities Corporation, APL's partner in the Sheerness project, have submitted an application to further delay the commissioning of Sheerness Unit 2 to 1990. The request for delay followed the Alberta Electric Utility Planning Council's 1984 forecast which, for the second consecutive year, projected a slowing in the rate of growth in electric energy demand in the Province. Hearings into the applications were recently concluded and the Company is awaiting a decision on the request. Of the $147.7 million invested in electric utility operations in 1984, $91.6 million was spent on the Sheerness project.

Capital Expenditures

	1984	1985 Estimate
	($ Millions)	
Electric	**147.7**	162.9
Natural Gas	**72.9**	95.8
Non-Utility		
Energy	**28.9**	29.6
Other	**.6**	
Intercompany		
Transfers	**(7.6)**	
	242.5	288.3

Capital additions in natural gas utility operations to provide for customer growth and to meet the requirements of existing customers totalled $72.9 million. The largest project in natural gas utility operations was the salt cavern storage facility. The facilities will be used to store gas to supply customers' peaking requirements. During 1984 the Company commissioned two of the five caverns under development.

Capital expenditures in ATCOR Resources Limited were a record $28.9 million, the largest segment of which was invested in exploration and production activities.

If a delay in the commissioning date of Sheerness Unit 2 from 1987 to 1990 is approved, the consolidated capital program would be in excess of $1.6 billion during the 1985-1990 time period. This projection assumes that the decline in economic activity which has beset the Province is now reaching its final stages and that a period of greater stability and reasonable economic growth can be expected in the medium to long term.

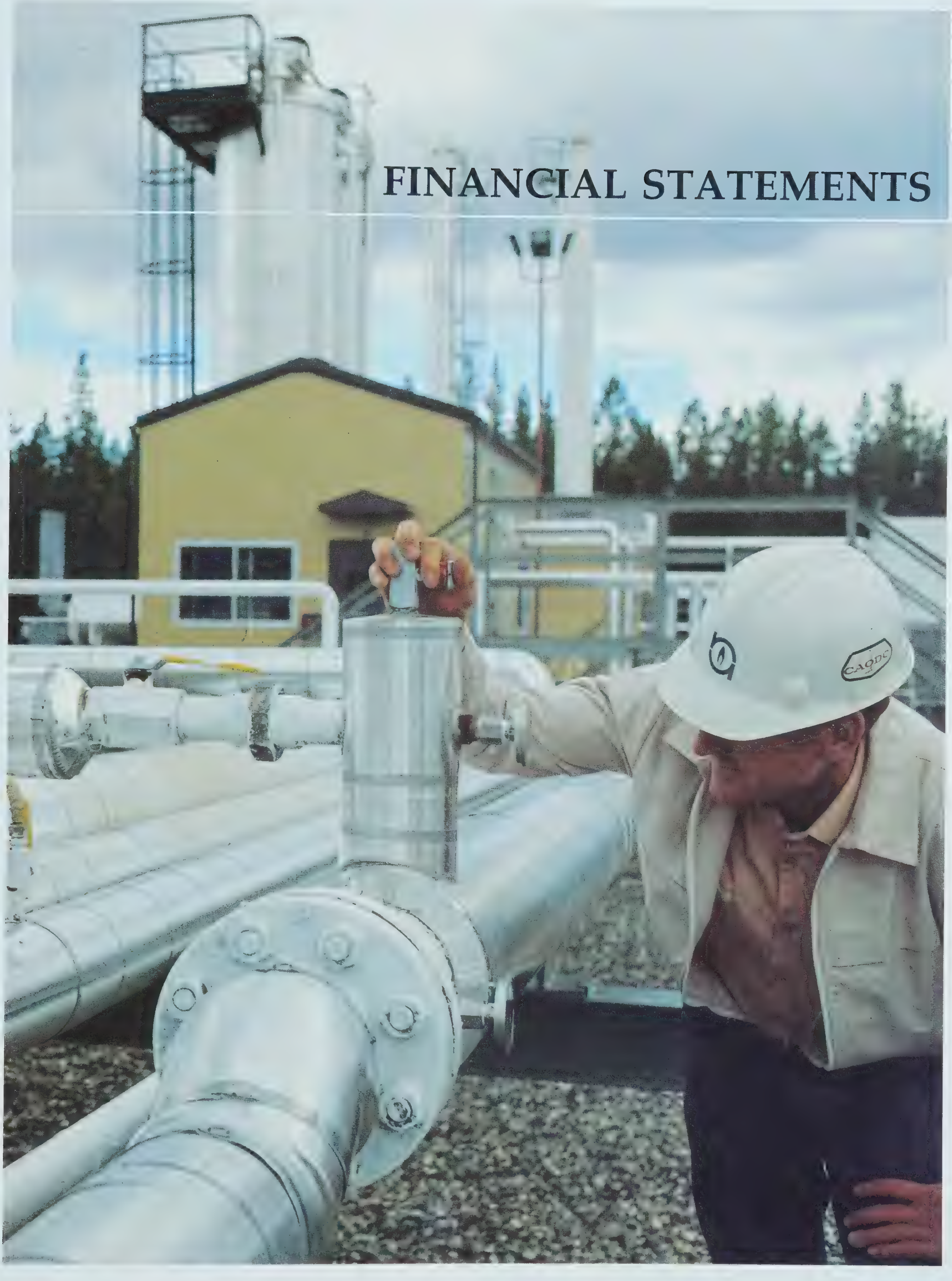
Permanent external financings in 1984 totalled $127.0 million. These financings included a private placement of $27.0 million of Cumulative Redeemable Second Preferred Shares, Series J. The issue was priced at $25.00 to yield 8.375%. The Company applied the proceeds of the placement to the redemption of its 10¼% Cumulative Redeemable Second Preferred Shares, Series A, which were redeemed at $25.70 a share, including $0.45 of accrued dividends. The Company also issued $100.0 million 13.10% debentures with a 10-year maturity in the Canadian market. Proceeds from the issue were applied to the Company's regular capital expenditure program.

The Company's capitalization structure includes the $288.6 million Series H preferred share issue that does not form part of the capital structures of the utility subsidiaries but is instead offset against the Company's investment in TransAlta Utilities Corporation. The Company reached an agreement with TransAlta on August 3, 1982 whereby each company would divest itself of each other's interlocking equity ownership over a period of three to five years. The Company fulfilled the first stage of its obligation under the agreement when on December 1, 1982 it issued one warrant to each Series H shareholder for each share held entitling the holder to purchase one Class A common share of TransAlta owned by CU, at a price of $22.25 per share on or before November 1, 1987. The exercise price is above the $18.81 average price per share paid when the investment was acquired. Gains are recognized when the warrants are exercised. To date, of the 12,971,900 warrants issued, 2,383 have been exercised.

The Company strives to maintain a target capitalization structure of 25% preferred equity, 35% common equity and 40% long-term debt (excluding the Series H preferred share issue). The 1984 capitalization calculation expressed on the same basis is 27% preferred equity, 37% common equity and 36% long-term debt.

The Company prides itself in having retained its premium credit standings throughout these very difficult economic times. The Company's credit rating position on senior debt instruments is AAA and A+ (High) and its preferred shares are rated AA (High) and P1 by the two major Canadian rating agencies, Dominion Bond Rating Service and Canadian Bond Rating Service respectively.

FINANCIAL STATEMENTS



MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The consolidated financial statements and other financial information relating to the Company contained in this annual report have been prepared by management, which is responsible for the integrity and objectivity of this information. The financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles as applied to regulated utilities and conform in all material respects with International Accounting Standards. These consolidated financial statements necessarily include some amounts that are based on informed judgements and best estimates of management.

Management depends upon a system of internal accounting controls to meet its responsibility for reliable and accurate reporting which includes periodic reviews by the internal audit function. Management modifies and improves its system of internal accounting controls in response to changes in business conditions.

Price Waterhouse, the Company's independent auditors, are engaged to express a professional opinion on the consolidated financial statements. The examination is conducted in accordance with generally accepted auditing standards and includes tests and other procedures which allow the auditors to report on the fairness of the consolidated financial statements prepared by management.

Under provisions of the Canada Business Corporations Act, the Board of Directors appoints certain of its members to serve on the Audit Committee. The Board of Directors, through this committee comprised of five non-management directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters, gain assurance that management is carrying out its responsibilities and to review and approve the financial statements. The internal auditors have full and free access to the Audit Committee.

AUDITORS' REPORT

To the Shareholders of
Canadian Utilities Limited:

We have examined the consolidated balance sheet of Canadian Utilities Limited as at December 31, 1984 and the consolidated statements of earnings and retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1984 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants

Edmonton, Canada
February 1, 1985

Consolidated Statement of Earnings and Retained Earnings

	Note	Year ended December 31 1984	1983
		(Thousands)	
Revenues		**$1,364,430**	$1,379,810
Operating Expenses			
Natural gas supply	1	**517,280**	512,621
Operation and maintenance		**375,418**	327,342
Taxes — other than income	2	**118,646**	231,273
Taxes — income	3	**108,544**	92,692
Depreciation		**65,187**	56,767
		1,185,075	1,220,695
		179,355	159,115
Allowance for Funds Used During Construction		**39,459**	33,182
Other Income	4	**31,268**	30,783
		250,082	223,080
Interest Expense		**75,469**	69,117
Dividends on Preferred Shares	11	**73,208**	66,847
		148,677	135,964
Earnings Attributable to Class A and Class B Shares		**101,405**	87,116
Retained Earnings at Beginning of Year		**242,618**	201,775
		344,023	288,891
Deduct			
Dividends on Class A and Class B shares	12	**58,549**	46,273
Retained Earnings at End of Year		**$ 285,474**	$ 242,618
Earnings per Class A and Class B Share		**$ 1.87**	$ 1.62

Consolidated Balance Sheet

	Note	December 31 1984	1983
		(Thousands)	
ASSETS			
Current Assets			
Cash and short-term investments		**$ 27,033**	$ 93,571
Accounts receivable	5	**169,606**	173,553
Materials and supplies		**18,632**	18,121
Natural gas stored		**2,661**	
Prepaid expenses		**4,141**	2,929
		222,073	288,174
Investment in TransAlta Utilities Corporation	13	**244,148**	244,509
Property, Plant and Equipment	6	**1,962,206**	1,787,899
Deferred Expenses	7	**40,853**	46,170
		$2,469,280	$2,366,752
LIABILITIES AND CAPITALIZATION			
Current Liabilities			
Due to bank		**$ 24,798**	$ 40,961
Accounts payable and accrued liabilities		**186,494**	210,494
Income and other taxes		**32,266**	34,435
Dividends payable		**12,525**	12,781
Long-term debt — current maturities		**11,225**	8,136
		267,308	306,807
Deferred Credits			
Contributions for extensions to plant		**169,331**	155,671
Deferred income taxes		**16,993**	12,461
Other	8	**45,543**	38,424
		231,867	206,556
Capitalization			
Long-term debt	10	**603,193**	527,238
Preferred shares	11	**750,812**	752,907
Class A and Class B shareholders' equity	12	**616,100**	573,244
		1,970,105	1,853,389
		$2,469,280	$2,366,752

APPROVED BY THE BOARD:

J. D. Wood, Director

D. R. B. McArthur, Director

Consolidated Statement of Changes in Financial Position

	Year ended December 31	
	1984	1983
	(Thousands)	
Sources of Funds		
Internal sources		
Earnings attributable to Class A and Class B shares	**$101,405**	$ 87,116
Depreciation	**65,187**	56,767
Other	**12,806**	11,030
Allowance for funds used during construction — shareholders' equity	**(15,748)**	(13,717)
Provided by operations	**163,650**	141,196
Deduct dividends on Class A and Class B shares	**58,549**	46,273
Provided internally	**105,101**	94,923
External sources		
Issue of long-term debt	**100,000**	15,860
Issue of preferred shares	**27,000**	100,000
Issue of Class A and Class B shares		3,816
Contributions for extensions to plant	**18,905**	25,872
Disposition of property, plant and equipment	**1,628**	518
Other	**2,377**	3,948
Provided externally	**149,910**	150,014
	$255,011	$244,937
Disposition of Funds		
Additions to property, plant and equipment	**$242,478**	$290,185
Decrease in deferred expenses for natural gas exploration — net	**(1,041)**	(8,026)
Allowance for funds used during construction — shareholders' equity	**(15,748)**	(13,717)
	225,689	268,442
Reduction in long-term debt	**24,045**	15,596
Preferred shares redeemed	**26,425**	
Preferred shares purchased for cancellation	**2,670**	1,715
Increase in other deferred expenses	**2,784**	4,457
Decrease in working capital	**(26,602)**	(45,273)
	$255,011	$244,937

Summary of Significant Accounting Policies

December 31, 1984

Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and conform in all material respects with the International Accounting Standards adopted by the International Accounting Standards Committee.

The consolidated financial statements include the accounts of the Company, the utility subsidiaries, Alberta Power Limited (electric), Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited (natural gas), and a non-utility subsidiary, ATCOR Resources Limited.

The preferred dividends are recorded in the same manner as interest expense in the consolidated statement of earnings and retained earnings. The capitalization segment of the consolidated balance sheet and the consolidated statement of earnings and retained earnings reflect the financing and cost of capital policies of the Company as a regulated utility in Alberta.

Regulation

The utility subsidiaries are regulated primarily by the Public Utilities Board of Alberta and the Energy Resources Conservation Board of Alberta, which administer acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The Public Utilities Board may award interim rates, subject to final determination. Decisions made by these authorities which impact on operating results or accounting policies are reflected in the consolidated financial statements from the date of decision.

Revenue Recognition

Revenues are recognized on the basis of cycle billings and are recorded when customers are billed.

Property, Plant and Equipment

The utility subsidiaries include in the cost of additions, an allowance for funds used during construction, at a rate approved by the Public Utilities Board for debt and equity funds.

Certain additions are made with the assistance of cash contributions where the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

On retirement of depreciable assets, the accumulated depreciation is charged with the cost of the retired unit less net salvage. Gains and losses on extraordinary retirements are recognized in earnings as extraordinary items.

Included in the natural gas subsidiaries' Property, Plant and Equipment are gas wells that have been drilled, tested and capped and remain unconnected to the utility system. The Public Utilities Board has directed that the costs of such wells, including an allowance for funds, be accounted for as plant held for future use. If, after a period of five years, these wells have not been added to the utility system, the costs are written off against funds received under The Natural Gas Price Administration Act. If at a future date a gas well is placed in service or is required to be used, the amount written off will be reinstated in Property, Plant and Equipment.

The non-utility subsidiary follows the full cost method of accounting for petroleum and natural gas properties whereby all costs relating to the exploration for, and development of, petroleum and natural gas reserves are capitalized.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. The major assets are depreciated using rates approved by the Public Utilities Board varying from 1.5% to 6.4%. All resource properties are depleted on a unit of production basis.

Investment in TransAlta Utilities Corporation

The investment in TransAlta Utilities Corporation is accounted for by the cost method. Income from this investment is recognized as dividends are declared.

Leases

The Public Utilities Board requires that application be made for the capitalization of leases in the determination of customer rates. Prior to such approval, leases that would otherwise be treated as capital leases are accounted for as operating leases.

Inventories

Inventories are valued at the lower of cost or net realizable value. Costs for materials and supplies are determined on an average basis, whereas the cost of natural gas stored is determined on a first in, first out basis.

Deferred Expenses

The natural gas subsidiaries include in gas exploration all costs, including an allowance for funds, related to the development of gas reserves. These costs are recorded net of income taxes. Costs related to a successful venture are capitalized as plant and equipment. The costs of an unsuccessful venture are charged against amounts received under The Natural Gas Price Administration Act included in other deferred credits.

Expenses of issue of long-term debt are amortized over the weighted average life of the debt and expenses of issue of preferred shares are amortized over the expected life of the issue.

Other deferred expenses are amortized over various periods not exceeding 40 years.

Deferred Credits

As Alberta gas producers, the natural gas subsidiaries receive a pro rata share of monies available under The Natural Gas Price Administration Act. The amounts received, net of royalties and income taxes, are deferred and, subject to Public Utilities Board approval, are reduced by the costs of unsuccessful natural gas exploration.

Taxes — Income

Income taxes are provided by the utility subsidiaries, using the normalized-all taxes paid method approved by the Public Utilities Board. This method eliminates differences between accounting earnings and taxable income which cause deferral of income taxes. The major portion of income taxes paid are refunded for rebate to customers under the Public Utilities Income Tax Transfer Act and the Utility Companies Income Tax Rebates Act.

Prior to adoption of this method, the utility subsidiaries provided for income taxes on the flow-through method which caused a deferral of income taxes. As the income tax component of rates is designed to recover only income taxes currently payable, no provision has been made in the consolidated financial statements for this deferral of income taxes. The customer in future years will bear an additional charge in the event of a drawdown of these unbooked deferred income taxes. A significant drawdown is not expected in the foreseeable future.

The deferral method is used by the Company and its non-utility subsidiary, except where under the terms of a cost of service agreement, the subsidiary is only allowed to include income taxes currently payable in the revenues billed.

Natural Gas Supply

The Province of Alberta enacted the Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas customers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the natural gas subsidiaries incur a lower effective cost for natural gas in that they are reimbursed for the portion of the price paid to their suppliers which exceeds the support price.

Alberta Electric Energy Marketing Agency

The Province of Alberta has established the Alberta Electric Energy Marketing Agency to reduce rate differentials for Alberta consumers by the purchase and resale of energy. The Agency buys energy from the utilities at each utility's cost of generation and transmission and resells identical quantities of energy at an average cost. The electric subsidiary receives funds monthly from the Agency and deposits these funds in a special trust account for rebate to its customers.

Notes to Consolidated Financial Statements

December 31, 1984

1. Natural gas supply

The natural gas supply expense is net of a rebate from the Province of Alberta of $102,755,000 (1983 — $91,365,000).

2. Taxes — other than income

	Year ended December 31	
	1984	1983
	(Thousands)	
Federal natural gas and gas liquids taxes	**$ 15,662**	$114,652
Federal petroleum and natural gas revenue taxes	**7,067**	7,890
Federal Canadian ownership taxes	**30,004**	42,336
	52,733	164,878
Franchise taxes	**52,290**	52,765
Property taxes	**12,388**	11,737
Provincial mineral taxes	**1,235**	1,893
	$118,646	$231,273

Since February 1, 1984 no natural gas and gas liquids taxes have been levied.

3. Taxes — income

Deferred income taxes of $4,246,000 (1983 — $5,368,000) have been provided for timing differences in the Company and its non-utility subsidiary. Under the normalized-all taxes paid method of accounting for income taxes the expected rate of income tax on accounting earnings would equal the statutory rate in the absence of permanent differences. The following table describes the permanent differences and their effect on the statutory rate:

	Year ended December 31	
	1984	1983
Statutory income tax rate	**47.0%**	47.9%
Allowance for funds used during construction	**(4.1)**	(4.2)
Crown royalties and other non-deductible Crown payments	**3.4**	5.2
Earned depletion and resource allowance	**(4.3)**	(5.5)
Dividend income	**(3.2)**	(3.5)
Alberta royalty tax credit	**(.7)**	(1.6)
Other	**.2**	(.7)
Actual income tax rate	**38.3%**	37.6%

A provision for certain deferred income taxes is not included in the consolidated financial statements. Unbooked deferred income taxes decreased during the year by $1,960,000 (1983 — increase of $1,431,000) to an accumulated amount of $129,171,000.

4. Other income

	Year ended December 31	
	1984	1983
	(Thousands)	
Interest	**$ 9,521**	$11,054
Dividends	**19,394**	18,019
Gain on purchase of long-term debt	**1,862**	845
Other	**491**	865
	$31,268	$30,783

5. Accounts receivable

	December 31	
	1984	1983
	(Thousands)	
Customer accounts	**$ 97,736**	$100,829
Receivable from the Province of Alberta	**29,622**	33,183
Other receivables and deposits	**42,248**	39,541
	$169,606	$173,553

6. Property, plant and equipment

	December 31			
	1984		1983	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Natural gas plant and equipment	**$ 913,670**	**$198,389**	$ 835,667	$175,889
Electric plant and equipment	**1,041,844**	**232,847**	983,607	195,491
Construction work in progress	**321,592**		246,174	
Non-regulated petroleum and natural gas properties	**99,817**	**18,914**	71,359	12,333
Other plant and equipment	**30,635**	**9,192**	29,573	7,806
Land	**13,990**		13,038	
	$2,421,548	**$459,342**	$2,179,418	$391,519
Net property, plant and equipment	**$1,962,206**		$1,787,899	

The electric subsidiary has a 50% joint ownership in the Sheerness Generating Station and is responsible for funding its share of construction costs. This is included in construction work in progress in the amount of $295,841,000 (1983 — $212,607,000).

Plant held for future use in the amount of $30,399,000 (1983 — $24,791,000) is included in natural gas plant and equipment.

7. Deferred expenses

	December 31	
	1984	1983
	(Thousands)	
Gas exploration — net	**$20,539**	$21,462
Unamortized debt and preferred share issue expenses	**18,465**	21,964
Other	**1,849**	2,744
	$40,853	$46,170

8. Other deferred credits

	December 31 1984	1983
	(Thousands)	
Funds received under The Natural Gas Price Administration Act — net	**$35,076**	$32,057
Other	**10,467**	6,367
	$45,543	$38,424

During the year there were no unsuccessful gas exploration costs charged against monies received under The Natural Gas Price Administration Act (1983 — $1,811,000 net of related income taxes).

9. Bank line of credit

Under a bank loan agreement, which provides a line of credit of up to $50,000,000 to March 14, 1986, the Company issues commercial paper and assumes bank loans. Under the agreement the Company maintains an unused bank line of credit of not less than 50% of the commercial paper outstanding. At December 31, 1984 and 1983 there were no bank loans outstanding.

10. Long-term debt

Long-term debt outstanding, net of current maturities, is as follows:

	December 31 1984	1983
	(Thousands)	
Canadian Utilities Limited		
Sinking fund debentures 8⅜% to 17.50% due to 2002	**$504,504**	$421,587
Capitalized lease obligation due 1996	**20,256**	21,086
Finance contract at 9.118% due 1990	**6,930**	7,860
Note payable due 1986	**8,000**	8,000
Alberta Power Limited		
First mortgage sinking fund bonds 5½% to 6½% due to 1992	**25,000**	25,000
Sinking fund debentures 7¼% to 9⅝% due to 1991	**14,844**	16,369
Northwestern Utilities Limited		
First mortgage sinking fund bonds 5⅜% to 9¾% due to 1994	**12,009**	12,941
Sinking fund debentures 7¼% due 1985		2,070
Canadian Western Natural Gas Company Limited		
First mortgage sinking fund bonds 5⅝% to 7% due to 1992	**6,525**	6,825
Sinking fund debentures 9¾% due 1990	**5,125**	5,500
	$603,193	$527,238

During 1984 the Company issued for cash $100,000,000 of 13.10% Debentures 1984 Series.

The $8,000,000 note payable is owing to Rural Electrification Associations and bears interest determined at May 15 and November 15 of each year at the greater of a bank's prime rate or its five-year term deposit rate.

Annual repayment of maturing issues, capitalized lease and finance contract requirements and sinking fund requirements for each of the following years are:

	Maturing Issues	Capitalized Lease and Finance Contract	Sinking Fund Requirements	Sinking Fund Purchased in Advance	Total
			(Thousands)		
1985	$ 2,070	$1,759	$19,417	$(12,021)	$11,225
1986	8,000	2,280	24,417	(2,076)	32,621
1987	40,000	2,349	24,417		66,766
1988	11,940	2,424	23,352		37,716
1989	2,125	2,505	23,227		27,857

The Company leases, with an option to purchase, a dragline costing $24,818,000 which is included in electric plant and equipment. The future minimum lease payments in aggregate are $34,381,000 of which $2,421,000 per year is payable in each of the five succeeding years. The imputed interest, included in these future minimum rentals, at the rate of 7.62% implicit in the lease is $13,295,000.

11. Preferred shares

	December 31		Dividends Year ended December 31	
	1984	1983	**1984**	1983
	(Thousands)		**(Thousands)**	
Canadian Utilities Limited	**$710,804**	$712,899	**$70,923**	$64,332
Northwestern Utilities Limited	**10,500**	10,500	**420**	420
Canadian Western Natural Gas Company Limited	**9,508**	9,508	**440**	440
ATCOR Resources Limited	**20,000**	20,000	**1,425**	1,655
	40,008	40,008	**2,285**	2,515
	$750,812	$752,907	**$73,208**	$66,847

Canadian Utilities Limited

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares.

150,000 Series Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Preferred Shares and rank pari passu with the 5% Cumulative Redeemable Preferred Shares.

An unlimited number of Series Second Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Second Preferred Shares.

Issued:

	December 31			
	1984		1983	
	Shares	**Amount**	Shares	Amount
		(Thousands)		(Thousands)
Cumulative Redeemable Preferred Shares				
5%	40,000	**$ 4,000**	40,000	$ 4,000
Cumulative Redeemable Preferred Shares				
4¼% Series	15,000	**1,500**	15,000	1,500
6% Series	50,000	**5,000**	50,000	5,000
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
10¼% Series A			1,057,000	26,425
9.24% Series B	1,391,600	**34,790**	1,420,600	35,515
7.30% Series C	993,580	**24,840**	1,023,380	25,584
		70,130		98,024
Retractable				
10.24% Series D	1,927,700	**48,192**	1,927,700	48,192
10.12% Series E	2,124,100	**53,103**	2,124,100	53,103
14.00% Series F	2,998,100	**74,952**	2,998,200	74,955
14.50% Series G	2,000,000	**50,000**	2,000,000	50,000
9.00% Series H	12,971,900	**288,625**	12,971,900	288,625
8.74% Series I	3,952,100	**98,802**	4,000,000	100,000
8.375% Series J	1,080,000	**27,000**		
		640,674		614,875
		$710,804		$712,899

During 1984 the Company redeemed the 10¼% Cumulative Redeemable Second Preferred Shares Series A. The redemption price was $25.25 per share, plus $0.45 of accrued dividends. The redemption was funded by a $27,000,000 private placement of Cumulative Redeemable Second Preferred Shares Series J.

Stated values, redemption premiums and dividends:

	Stated Value	1985 Redemption Premium	Dividends Year ended December 31 1984	1983
			(Thousands)	
Cumulative Redeemable Preferred Shares				
5%	$100	4%	**$ 200**	$ 226
Cumulative Redeemable Preferred Shares				
4¼% Series	$100	2½%	**64**	72
6% Series	$100	2%	**300**	350
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
10¼% Series A	$25		**471**	2,715
9.24% Series B	$25	2%	**3,253**	3,320
7.30% Series C	$25	2.4%	**1,843**	1,896
			6,131	8,579
Retractable				
10.24% Series D	$25	4%	**4,935**	4,929
10.12% Series E	$25		**5,374**	5,366
14.00% Series F	$25		**10,494**	10,515
14.50% Series G	$25		**7,250**	7,260
9.00% Series H	$22.25		**25,976**	26,223
8.74% Series I	$25		**8,694**	1,460
8.375% Series J	$25		**2,069**	
			64,792	55,753
			$70,923	$64,332

Redemption

The preferred shares of the Company are redeemable subject to premiums listed above plus accrued dividends. The Cumulative Redeemable Preferred Shares and the non-retractable Cumulative Redeemable Second Preferred Shares are redeemable at the option of the Company at any time. The retractable Cumulative Redeemable Second Preferred Shares will be subject to redemption at the option of the Company commencing at the dates specified and with an initial premium as stated:

		Redemption Premium
Series D	June 1, 1985	4%
Series E	March 1, 1986	4%
Series F	October 1, 1986	4%
Series G	May 1, 1987	4%
Series H	November 1, 1987	Nil
Series I	November 1, 1988	4%
Series J	January 31, 1992	Nil

Purchase obligations

The Company is required in each year to make all reasonable efforts to purchase for cancellation the number of shares of the Cumulative Redeemable Second Preferred Shares listed below at a price not exceeding $25 per share plus costs of purchase. If after all reasonable efforts the Company is unable to do so, the Company's obligation to purchase in such year is extinguished.

	1984 Share Purchase Obligations	Purchased in 1984 Shares	Purchased in 1984 Amount
			(Thousands)
Series B	48,000	29,000	**$ 725**
Series C	36,000	29,800	**744**
Series D	40,000		
Series E	44,000		
Series F	119,982	100	**3**
Series G	80,000		
Series I	120,000	47,900	**1,198**
			$2,670

Retraction privileges

Certain series of the Cumulative Redeemable Second Preferred Shares have retraction privileges on specified dates at the option of the holder at the stated value plus accrued dividends. The series and retraction dates are shown below:

Series D	June 1, 1985 and June 1, 1990
Series E	March 1, 1988
Series F	October 1, 1989
Series G	May 1, 1987
Series H	November 1, 1987
Series I	November 1, 1991
Series J	January 31, 1992

The Series H Cumulative Redeemable Second Preferred Shares can be redeemed at the option of the holder prior to November 1, 1987 if presented with a warrant to purchase a Class A common share of TransAlta Utilities Corporation.

Northwestern Utilities Limited

	December 31 **1984**	December 31 1983
	(Thousands)	
Authorized and issued:		
105,000, 4% Cumulative Redeemable Preferred Shares — $100; voting, non-participating, 1985 redemption premium — 4%	**$10,500**	$10,500

Canadian Western Natural Gas Company Limited

	December 31 **1984**	December 31 1983
	(Thousands)	
Authorized and issued:		
275,410, 4% Cumulative Redeemable Preferred Shares — $20; voting, non-participating, 1985 redemption premium — 3%	**$5,508**	$5,508
200,000, 5½% Cumulative Redeemable Preferred Shares — $20; ; voting, non-participating, 1985 redemption premium — 3%	**4,000**	4,000
	$9,508	$9,508

	December 31 1984	December 31 1983
	(Thousands)	
Authorized and issued:		
800,000 Floating Rate Cumulative Redeemable Preferred Shares — $25; guaranteed by the Company, dividend rate of one-half of bank prime rate plus 1¼%, redemption of $2,000,000 per year commencing in 1989 — nil premium	**$20,000**	$20,000

12. Class A and Class B shareholders' equity

	December 31 1984	December 31 1983	Dividends Year ended December 31 1984	Dividends Year ended December 31 1983
	(Thousands)		(Thousands)	
Class A non-voting shares	**$168,227**	$166,681	**$29,693**	$23,153
Class B common shares	**162,399**	163,945	**28,856**	23,120
Retained earnings	**285,474**	242,618		
	$616,100	$573,244	**$58,549**	$46,273

Class A and Class B shares

Authorized:

An unlimited number of Class A non-voting shares and Class B common shares without nominal or par value.

Issued:

	Year ended December 31, 1984			
	Class A non-voting		Class B common	
	Shares	Amount (Thousands)	Shares	Amount (Thousands)
Beginning of year	27,331,024	**$166,681**	26,880,550	**$163,945**
Share exchanges	253,421	**1,546**	(253,421)	**(1,546)**
End of year	27,584,445	**$168,227**	26,627,129	**$162,399**

The holders of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by the Company on either of such classes of shares as well as the remaining property of the Company upon dissolution. The holders of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share. The holders of the Class A non-voting shares are entitled to exchange, in limited circumstances, each share held for one Class B common share.

Retained earnings

The bond and debenture indentures place certain limitations on the Company which include restrictions on the payment of dividends on Class A and Class B shares. Consolidated retained earnings in the amount of $135,374,000 was free from such restrictions.

13. Investment in TransAlta Utilities Corporation

On August 3, 1982, the Company, ATCO Ltd. and TransAlta Utilities Corporation entered into an agreement providing for the divestiture of the interlocking equity ownership positions held by the Company and TransAlta Utilities Corporation. Subject to market conditions prevailing from time to time, the intended divestiture period is three years with a provision for an extension of up to two additional years.

On December 1, 1982 each Series H preferred shareholder was issued a warrant, for each share held, entitling the bearer to purchase one Class A common share of TransAlta Utilities Corporation owned by the Company at a price of $22.25 per share on or before November 1, 1987. The investment in TransAlta Utilities Corporation was acquired at an average price of $18.81 per share. Gains on disposition are recorded as warrants are exercised. As of December 31, 1984, 2,383 warrants had been exercised.

14. Amounts held in trust

	December 31	
	1984	1983
	(Thousands)	
Rural Electrification Associations	**$14,427**	$13,470
Income tax rebates	**5,312**	13,259
Alberta Electric Energy Marketing Agency	**1,161**	3,377
	$20,900	$30,106

Amounts held in trust are not included in the consolidated financial statements.

15. Related party transactions

During 1984 payments were made to ATCO Ltd., the principal shareholder of the Company, and certain of its subsidiaries. All of these transactions are considered to be in the normal course of business and at fair value. Payments were made for management fees of $256,000 (1983 — $524,000), the rental of premises of $11,522,000 (1983 — $7,334,000) and equipment purchases of $726,000 (1983 — $737,000). A subsidiary of ATCO Ltd. acted as a general contractor for construction of a warehouse facility and office leasehold improvements for which fees, including administration costs, amounted to $176,000 (1983 — $1,152,000). Certain subsidiaries of the Company participate in oil and natural gas joint ventures. When they act as operator they have, in some instances, contracted ATCO Ltd. subsidiaries for well drilling and servicing, equipment purchases and related services, the total amount being approximately $3,700,000 (1983 — $5,500,000). A portion of these expenditures is reimbursed by the other participants in the joint ventures. The Company was reimbursed by ATCO Ltd. and certain of its subsidiaries for the provision of security services in the amount of $279,000 (1983 — nil). Charges to ATCO Ltd. for rental of premises and recovery of costs of leasehold improvements were $105,000 (1983 — nil).

16. Rate applications

One of the natural gas subsidiaries received an interim rate decision effective October 1984. The application was for an additional $23,000,000 of revenue in 1984. The Public Utilities Board approved interim rates which were estimated to allow the natural gas subsidiary to recover $10,000,000 in the period November 1, 1984 to June 30, 1985, of which approximately $5,000,000 was recorded in 1984.

The Public Utilities Board, by an order dated January 17, 1985, directed the electric subsidiary to file a submission for a general rate proceeding covering the test years 1984 and 1985. After reviewing the rates allowed for 1984, the Public Utilities Board may or may not amend the rates the electric subsidiary charged to its customers. It is not possible, at this time, to forecast the outcome or effect of this proceeding.

17. Commitments and contingencies

The electric subsidiary has a 50% joint ownership in the Sheerness Generating Station which is under construction. The project presently is forecast to cost the electric subsidiary approximately $538,000,000, of which $242,000,000 is yet to be expended. Sheerness Unit I is planned to be completed in January 1986. The electric subsidiary has applied to the Energy Resources Conservation Board to defer commissioning of Sheerness Unit II from 1987 to 1990. A hearing was held in January 1985 and a decision is pending.

Minimum non-capitalized lease payments, which extend over periods not exceeding 19 years, are $13,381,000, $12,995,000, $12,638,000, $12,186,000 and $11,319,000 for the years 1985-1989, respectively.

The Company and its subsidiaries have a defined benefit pension plan covering substantially all employees. Pension costs for the year amounted to $12,181,000 (1983 — $13,774,000) including costs of unfunded liabilities of $4,656,000 (1983 — $4,933,000). Based on the most recent actuarial evaluation, December 31, 1983, the estimated unfunded liabilities at December 31, 1984 amount to approximately $31,460,000 which will be funded over a period not exceeding 14 years.

The utility subsidiaries purchase natural gas and coal from approximately 350 producers under approximately 580 purchase contracts. Substantially all of these contracts have provisions requiring payment by the company when it is unable to nominate specified minimum annual quantities for delivery. In prior years the available market has exceeded the minimum contract supply quantities and the company was not required to make "take-or-pay" payments.

During 1984 a major customer took less than the minimum annual volume of natural gas it had contracted to take from a natural gas subsidiary. As a result the subsidiary filed a Statement of Claim for $1,545,000 to recover the amount due under the sales contract. In 1985 the customer is continuing to take less than the contracted volumes. The subsidiary has invoked "force majeure" with regard to the 21 producers supplying natural gas dedicated to the major customer. The producer supplying the largest volume of natural gas has filed a Statement of Claim for $575,000 against the subsidiary. It is not possible at this time to forecast the outcome of these matters.

18. Segmented information

Operating segments	Year	Electric Utility Operations	Gas Utility Operations	Non-Utility Energy Operations	Non-Utility Other	Consolidated*
			(Thousands)			
Revenues						
Outside customers	**1984**	**$ 340,345**	**$861,218**	**$162,203**	**$ 664**	**$1,364,430**
	1983	$ 327,241	$928,427	$123,573	$ 569	$1,379,810
Inter-segment		**144**	**23,147**	**7,073**	**8,661**	
		143	22,819	7,211	5,135	
		340,489	**884,365**	**169,276**	**9,325**	**1,364,430**
		327,384	951,246	130,784	5,704	1,379,810
Expenses						
Operating		**141,419**	**755,413**	**144,206**	**9,331**	**1,011,344**
		134,727	856,994	108,745	6,079	1,071,236
Taxes — income		**60,356**	**36,373**	**9,643**	**2,172**	**108,544**
		58,213	24,189	9,055	1,235	92,692
Depreciation		**34,072**	**22,945**	**8,147**	**215**	**65,187**
		31,843	17,153	7,798	188	56,767
		235,847	**814,731**	**161,996**	**11,718**	**1,185,075**
		224,783	898,336	125,598	7,502	1,220,695
Segment operating income	**1984**	**$ 104,642**	**$ 69,634**	**$ 7,280**	**$ (2,393)**	**$ 179,355**
	1983	$ 102,601	$ 52,910	$ 5,186	$ (1,798)	$ 159,115
Total assets	**1984**	**$1,172,917**	**$894,179**	**$136,104**	**$298,379**	**$2,469,280**
	1983	$1,088,727	$846,417	$126,106	$314,435	$2,366,752
Capital expenditures	**1984**	**$ 147,709**	**$ 72,925**	**$ 28,922**	**$ 617**	**$ 242,478**
	1983	$ 171,832	$108,770	$ 9,558	$ 25	$ 290,185

* Inter-segment transactions have been eliminated in the consolidated column.

19. Financial statements

Certain of the 1983 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1984.

CONSOLIDATED TEN-YEAR FINANCIAL SUMMARY

(Dollars in millions, except as indicated)

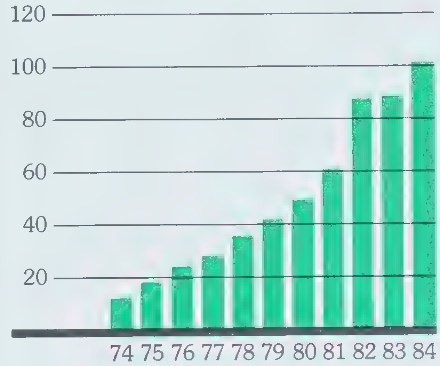
	1984	1983	1982
Operating Revenues			
Natural gas	**861.2**	928.4	959.1
Electric	**340.3**	327.2	316.3
Non-utility			
Energy	**162.2**	123.6	116.3
Other	**.7**	.6	.8
	1,364.4	1,379.8	1,392.5
Operating Expenses			
Natural gas supply	**517.3**	512.6	444.8
Operating and maintenance	**375.4**	327.3	326.2
Taxes — other than income	**118.7**	231.3	329.4
Taxes — income	**108.5**	92.7	78.5
Depreciation	**65.2**	56.8	53.1
	1,185.1	1,220.7	1,232.0
	179.3	159.1	160.5
Allowance for Funds Used During Construction	**39.5**	33.2	15.8
Other Income	**31.3**	30.8	27.2
	250.1	223.1	203.5
Interest Expense	**75.5**	69.1	74.1
Dividends on Preferred Shares	**73.2**	66.9	43.1
Earnings before Extraordinary Items	**101.4**	87.1	86.3
Extraordinary Items — Non-Recurring Gain (Loss)			
Earnings Attributable to Class A and Class B Shares	**101.4**	87.1	86.3
Contribution by Segment			
Electric	**62.9**	61.3	45.6
Natural gas	**34.2**	26.2	33.0
Non-utility			
Energy	**7.8**	5.6	5.1
Other	**(3.5)**	(6.0)	2.6
	101.4	87.1	86.3
Shares Outstanding* (thousands)			
At end of year	**54,212**	54,212	53,806
Average for year	**54,212**	53,807	50,910
Earnings per Share*# (dollars)	**1.87**	1.62	1.69
Total Annual Dividends*	**58.5**	46.3	35.8
Dividends per Share* (dollars)	**1.08**	.86	.71
Payout Ratio (dividends — earnings attributable)	**57.7%**	53.2%	41.5%
Equity per Share* (dollars)	**11.36**	10.57	9.82
Return on Equity*#	**17.1%**	15.9%	18.4%
Stock Market Record — Class A non-voting shares High	**17**	16¼	16
Low	**13¼**	11¾	8½
Close	**17**	15¾	15¾
Stock Market Record — Class B common shares High	**17**	16⅛	15½
Low	**13¼**	12	9¼
Close	**17**	15¾	15½
Property, Plant and Equipment — Gross	**2,421.5**	2,179.4	1,890.9
— Net	**1,962.2**	1,787.9	1,559.9
Total Assets	**2,469.3**	2,366.8	2,222.6
Capitalization			
Long-term debt	**603.2**	527.2	527.0
Preferred shares	**750.8**	752.9	654.6
Total long-term debt and preferred shares	**1,354.0**	1,280.1	1,181.6
Shareholders' equity*	**616.1**	573.2	528.6
Total capitalization	**1,970.1**	1,853.3	1,710.2
Capitalization Ratio			
Long-term debt	**31%**	28%	31%
Preferred shares	**38%**	41%	38%
Shareholders' equity*	**31%**	31%	31%
Times Debt Interest Earned (pretax)	**4.75**	4.57	3.81

* Includes Class A non-voting shares and Class B common shares.
Where Class A and Class B shares are presented the comparative figures have been reclassified to reflect the September 10, 1982 two-for-one share reorganization.

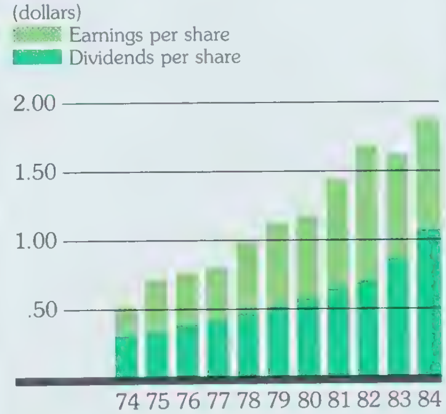
All information expressed before extraordinary items.

1981	1980	1979	1978	1977	1976	1975	1974
779.2	581.7	477.9	431.8	318.7	216.5	141.8	91.2
201.7	149.8	124.6	114.7	93.9	78.1	57.9	46.3
42.9	25.4	22.9	7.5	2.5	1.0	.5	
.8	.8	.3	.2	.3	.3	.2	.3
1,024.6	757.7	625.7	554.2	415.4	295.9	200.4	137.8
442.2	405.8	342.3	315.5	221.3	134.8	70.9	40.2
212.5	166.3	139.1	107.2	87.2	72.8	56.5	43.6
195.8	53.2	28.0	26.6	21.8	17.0	11.8	8.0
30.6	21.6	17.5	20.0	12.5	8.6	8.7	2.4
36.8	29.5	26.5	23.2	18.8	15.6	13.3	12.9
917.9	676.4	553.4	492.5	361.6	248.8	161.2	107.1
106.7	81.3	72.3	61.7	53.8	47.1	39.2	30.7
24.6	19.7	7.1	4.7	2.3	1.3	4.0	1.6
6.8	2.7	1.5	2.5	1.4	2.3	1.4	1.0
138.1	103.7	80.9	68.9	57.5	50.7	44.6	33.3
53.7	39.5	27.4	22.4	21.4	22.3	19.9	17.2
23.8	14.9	11.7	10.9	8.4	4.7	6.0	3.7
60.6	49.3	41.8	35.6	27.7	23.7	18.7	12.4
				(1.6)		2.4	.5
60.6	49.3	41.8	35.6	26.1	23.7	21.1	12.9
34.9	29.3	21.7	18.7	15.4	12.8	10.7	7.2
21.5	17.6	18.1	15.7	11.7	10.8	7.9	5.2
2.3	1.7	1.9	1.1	.2	.1	.1	
1.9	.7	.1	.1	.4			
60.6	49.3	41.8	35.6	27.7	23.7	18.7	12.4
45,936	41,636	41,636	37,252	34,244	33,268	28,396	20,150
41,822	41,984	37,566	36,293	34,624	31,134	28,516	28,432
1.44	1.19	1.12	.99	.81	.78	.73	.53
26.1	23.8	18.9	16.4	14.4	11.0	7.1	5.9
.63	.57	.51	.46	.43	.38	.33	.30
43.1%	48.3%	45.2%	45.9%	55.2%	46.4%	33.6%	45.7%
8.59	7.61	7.00	6.11	5.53	5.18	4.71	4.25
17.8%	16.3%	17.1%	17.0%	15.1%	15.8%	16.3%	12.8%
12½	13½	10½	9	7¾	7¼	5	5½
9¾	9⅛	8	7⅛	6⅜	4¾	3⅞	3¼
10⅞	11⅜	9½	8⅛	7¾	7¼	4⅞	3⅝
1,594.6	1,324.1	1,059.3	883.9	780.5	688.6	613.6	538.7
1,318.5	1,083.7	849.4	700.1	618.8	542.3	478.6	413.5
1,602.7	1,314.1	1,000.6	832.9	731.5	632.0	564.1	466.8
453.3	393.6	302.2	233.7	244.3	225.7	181.1	194.5
321.2	196.2	148.3	149.2	129.3	99.3	55.3	30.5
774.5	589.8	450.5	382.9	373.6	325.0	236.4	225.0
394.6	316.2	290.3	226.9	187.5	173.9	138.6	115.3
1,169.1	906.0	740.8	609.8	561.1	498.9	375.0	340.3
39%	43%	41%	38%	44%	45%	48%	57%
27%	22%	20%	25%	23%	20%	15%	9%
34%	35%	39%	37%	33%	35%	37%	34%
3.14	3.17	3.59	3.97	3.27	2.66	2.68	2.08

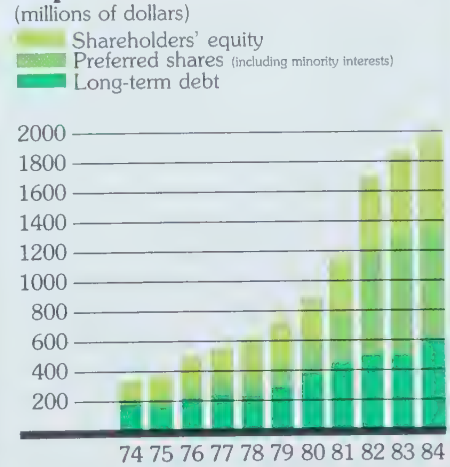
Earnings Attributable to Class A and Class B Shares
(before extraordinary items)
(millions of dollars)



Earnings and Dividends per Class A and Class B Share
(before extraordinary items)
(dollars)



Capitalization
(millions of dollars)



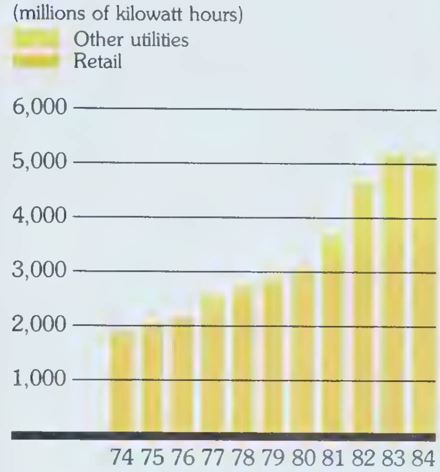
CONSOLIDATED TEN-YEAR OPERATING SUMMARY

(Dollars in millions, except as indicated)

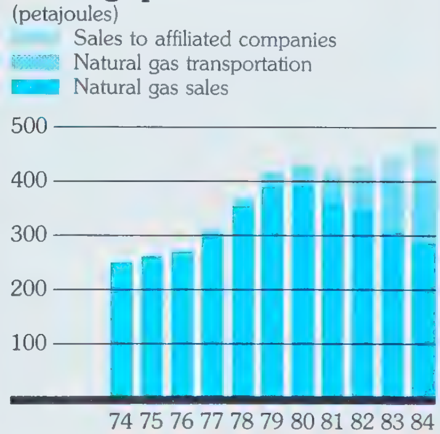
	1984	1983	1982
Electric Operations			
Property, plant and equipment in service	**1,046.8**	987.9	911.2
Construction work in progress	**314.5**	227.3	130.3
Property, plant and equipment — gross	**1,361.3**	1,215.2	1,041.5
Accumulated depreciation	**232.8**	195.5	158.8
Property, plant and equipment — net	**1,128.5**	1,019.7	882.7
Growth over prior year	**11%**	16%	16%
Capital expenditures	**147.7**	171.8	157.2
Sales (millions of kilowatt hours) — retail	**3,882**	3,618	3,452
— other utilities	**1,265**	1,552	1,196
Growth retail sales over prior year	**7%**	5%	7%
Average annual use per residential customer (kWh)	**7,264**	7,044	7,436
Average annual billing per residential customer ($)	**660**	643	661
Maximum hourly demand (thousands of kilowatts)	**741**	720	693
Generating capacity (thousands of kilowatts)	**1,055**	1,056	1,058
Customers at year-end (thousands)	**143.4**	139.9	136.6
Number of communities served	**399**	398	395
Power lines (thousands of kilometres)	**37.5**	34.6	29.2
Natural Gas Operations			
Property, plant and equipment — gross	**929.6**	863.2	757.9
Accumulated depreciation	**198.4**	175.9	159.9
Property, plant and equipment — net	**731.2**	687.3	598.0
Growth over prior year	**6%**	15%	24%
Capital expenditures	**72.9**	108.8	135.5
Sales (petajoules)	**286**	308	347
Transportation (petajoules)	**124**	98	63
Sales and transportation — affiliates (petajoules)	**61**	45	26
Total system throughput (petajoules)	**471**	451	436
Growth over prior year	**4%**	3%	2%
Average annual use per residential customer (gigajoules)	**166**	162	196
Average annual billing per residential customer ($)	**580**	586	625
Maximum daily demand (terajoules)	**2,119**	2,147	2,063
Degree days — Edmonton	**5,349**	5,362	6,025
— Calgary	**5,021**	4,953	5,602
Customers at year-end (thousands)	**593.6**	580.7	566.6
Number of communities served	**293**	289	285
Pipelines (thousands of kilometres)	**32.1**	31.1	30.4
Non-Utility Energy Operations			
Property, plant and equipment — gross	**125.9**	97.0	87.6
Accumulated depreciation	**26.9**	19.0	11.4
Property, plant and equipment — net	**99.0**	78.0	76.2
Production			
Oil (m^3/d)	**260**	189	158
Gas ($10^3m^3/d$)	**125**	170	170
Ethane (m^3/d)	**651**	736	780
LPGs (m^3/d)	**200**	170	184
Reserves			
Oil (10^3m^3)	**1,577**	1,408	889
Gas (10^6m^3)	**1,535**	1,224	1,182
Total Number of Employees	**4,099**	4,168	4,212

1981	1980	1979	1978	1977	1976	1975	1974
817.8	493.2	439.8	407.2	358.6	332.7	295.0	217.8
68.9	243.8	107.7	31.5	34.4	20.0	14.3	42.9
886.7	737.0	547.5	438.7	393.0	352.7	309.3	260.7
127.3	106.7	89.9	75.4	62.2	53.2	45.7	41.2
759.4	630.3	457.6	363.3	330.8	299.5	263.6	219.5
21%	38%	26%	10%	10%	14%	20%	20%
153.5	190.1	110.7	48.1	44.1	45.9	51.1	44.8
3,216	2,994	2,779	2,512	2,358	2,182	2,025	1,920
495	34	113	192	228			
7%	8%	11%	7%	8%	8%	5%	8%
6,988	7,073	7,162	7,058	6,764	6,773	6,673	6,251
474	405	366	358	310	281	223	187
652	607	573	520	524	455	445	388
1,054	670	668	668	671	686	686	523
134.6	128.8	120.1	112.5	106.9	99.6	94.0	88.8
399	395	392	387	385	368	365	364
25.3	23.7	23.0	22.3	20.8	20.1	19.3	18.8
624.7	553.9	479.8	416.8	370.9	333.9	300.8	275.5
142.9	129.7	117.7	107.6	99.3	93.0	89.3	83.9
481.8	424.2	362.1	309.2	271.6	240.9	211.5	191.6
14%	17%	17%	14%	13%	14%	10%	11%
80.9	75.6	64.5	48.2	38.8	39.4	29.5	25.7
364	392	392	357	304	273	264	251
51	42	30	16	12			
11	2	1	2				
426	436	423	375	316	273	264	251
(2%)	3%	13%	18%	16%	3%	5%	1%
165	190	207	201	190	195	224	219
434	336	308	299	241	190	156	115
2,048	2,051	2,003	1,978	1,681	1,508	1,390	1,295
4,595	5,396	5,636	5,530	5,124	4,891	5,555	5,492
4,365	5,082	5,366	5,592	5,289	4,885	5,750	5,230
549.8	520.0	489.8	457.4	428.4	400.5	373.3	353.3
272	269	272	265	260	257	253	253
29.3	27.9	27.1	25.0	23.1	21.8	19.5	16.7
79.2	29.3	28.2	26.3	15.5			
5.1	3.3	1.9	.3				
74.1	26.0	26.3	26.0	15.5			
142	79	67					
121	125	119					
952	1,039	1,044					
190	189	192					
750	766	694					
1,186	1,144	944					
4,313	4,144	3,870	3,592	3,367	3,161	3,133	2,933

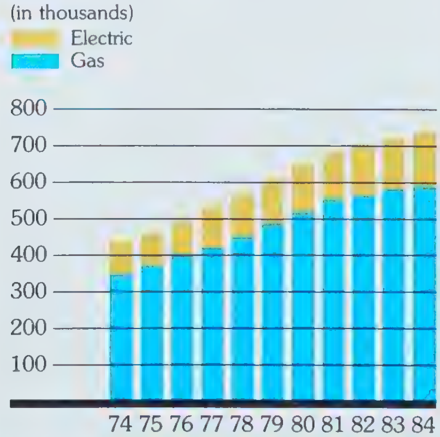
Electric Sales
(millions of kilowatt hours)



Natural Gas System Throughput
(petajoules)



Gas and Electric Customers at Year-end
(in thousands)



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CANADIAN UTILITIES LIMITED

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Calgary, Alberta

D. R. B. McArthur*
Corporate Director
Edmonton, Alberta

W. S. McGregor
President
Numac Oil & Gas Ltd.
Edmonton, Alberta

C. S. Richardson°
Senior Vice-President, Finance
ATCO Ltd.
Calgary, Alberta

D. M. Ritchie°
President
Medway Investments
Corporation Ltd.
Edmonton, Alberta

N. W. Robertson*
President and Chief Operating Officer
ATCO Ltd.
Calgary, Alberta

R. D. Southern°
Deputy Chairman and
Chief Executive Officer
ATCO Ltd.
Calgary, Alberta

J. D. Wood°+
President and Chief Operating Officer
Canadian Utilities Limited
Edmonton, Alberta

° member of Executive Committee
* member of Audit Committee
+ member of Human Resources Committee

Officers and Staff Executives

R. D. Southern
Chairman of the Board and
Chief Executive Officer

Subsidiary Company Executives

ALBERTA POWER LIMITED

R. D. Southern
Chairman of the Board and
Chief Executive Officer

J. D. Wood
Deputy Chairman of the Board

W. R. Horton
President and Chief Operating Officer

Keith Provost
Senior Vice-President

R. H. Choate
Vice-President, Administration

J. R. Frey
Vice-President, Planning

D. B. Mitchell
Vice-President, Human Resources

J. E. A. Morin
Vice-President, Engineering and
Construction

G. N. Paicu
Vice-President, Energy Supply

A. J. Pullman
Vice-President and Controller

C. O. Twa
Vice-President, Customer Services

A. M. Anderson
Secretary/Treasurer

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

D. P. Wood
Assistant Secretary

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED and NORTHWESTERN UTILITIES LIMITED

R. D. Southern
Chairman of the Board and
Chief Executive Officer

J. D. Wood
Deputy Chairman of the Board

W. R. Horton
President and Chief Operating Officer

B. M. Dafoe
Senior Vice-President

A. J. L. Fisher
Vice-President and General Manager
Canadian Western Natural Gas
Company Limited

R. G. Lock
Vice-President and General Manager
Northwestern Utilities Limited

W. L. Graburn
Vice-President, Gas Supply

D. B. Mitchell
Vice-President, Human Resources

A. M. Anderson
Secretary/Treasurer

H. R. Lewis
Controller, Northwestern
Utilities Limited

T. J. Storey
Controller, Canadian Western
Natural Gas Company Limited

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

CORPORATE INFORMATION

C. S. Richardson
Deputy Chairman of the Board

J. D. Wood
President and Chief Operating Officer

W. R. Horton
Executive Vice-President, Utilities

H. N. Bottomley
Vice-President and Controller

D. B. Mitchell
Vice-President, Human Resources

A. E. Scott
Vice-President, Corporate Planning and Economics

A. M. Anderson
Secretary

C. K. Sheard
General Counsel and Assistant Secretary

J. H. Cook
Assistant Secretary

D. P. Wood
Assistant Secretary

J. A. Walker
Treasurer

D. P. Wood
Assistant Secretary

ATCOR RESOURCES LIMITED

R. D. Southern
Chairman of the Board

J. D. Wood
Deputy Chairman of the Board

W. A. Elser
President and Chief Executive Officer

D. L. Weiss
Vice-President, Processing and Marketing

D. H. Boyle
Treasurer

R. E. Pratt
Controller

D. P. Wood
Secretary

A. M. Anderson
Assistant Secretary

CANADIAN UTILITIES LIMITED

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

Registered Head Office

10035 - 105th Street
Edmonton, Alberta, Canada
T5J 2V6
Telephone: (403) 420-7310

Valuation Day

The Valuation Day price of Canadian Utilities' Class A non-voting and Class B common shares adjusted for the stock split of September 15, 1972 and the replacement of common shares by the Class A and B shares on September 10, 1982 was $4.66

Annual Meeting

The annual meeting of shareholders will be held April 24, 1985 at the Four Seasons Hotel, Edmonton, Alberta.

Transfer Agents and Registrars

Halifax/Montreal/Toronto/Winnipeg/Regina/Calgary/Edmonton/Vancouver

Class A non-voting and Class B common shares
The Royal Trust Company

Preferred, Series Preferred and Second Preferred (Series B - I) Shares
The Canada Trust Company

Trustee and Registrar

Montreal/Toronto/Winnipeg/Calgary/Edmonton/Vancouver

Debentures
National Trust Company, Limited

Stock Exchange Listings

Class A non-voting and Class B common shares
Toronto, Montreal and Alberta Stock Exchanges

Preferred and Series Preferred Shares
Toronto Stock Exchange

Second Preferred (Series B - I) Shares
Toronto and Montreal Stock Exchanges

Euro-Dollar Debentures
London Stock Exchange

Auditors

Price Waterhouse
2401 Toronto Dominion Tower
Edmonton Centre
Edmonton, Alberta T5J 2Z1

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An ATCO Company